OLSON, BZDOK & HOWARD

August 29, 2017

Ms. Kavita Kale
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-filing

RE: MPSC Case No. U-18255

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Direct Testimony of Jonathan Wallach on behalf of the Natural Resources Defense Council, Michigan Environmental Council, and Sierra Club

Exhibits NRD-1 through NRD-4

Proof of Service

Sincerely,

Digitally signed by Christopher M. Bzdok
Date: 2017.08.29 12:35:05 -04'00'

Christopher M. Bzdok
Chris@envlaw.com

cc: Parties to Case No. U-18255, ALJ Mark D. Eyster (eysterm@michigan.gov)
Ariana Gonzalez, Natural Resources Defense Council (agonzalez@nrdc.org)
Samantha Williams, Natural Resources Defense Council (swilliams@nrdc.org)
James Clift, MEC (james@environmentalcouncil.org)
Elena Saxonhouse, Sierra Club (elena.saxonhouse@sierraclub.org)
Casey Roberts, Sierra Club (casey.roberts@sierraclub.org)
Kristin Henry, Sierra Club (kristin.henry@sierraclub.org)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	**)**	
DTE Electric Company for authority to	**)**	
increase its rates, amend its rate schedules	**)**	**Case No. U-18255**
and rules governing the distribution and	**)**	
supply of electric energy, and for	**)**	**ALJ Mark D. Eyster**
miscellaneous accounting authority	**)**	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE NATURAL RESOURCES DEFENSE COUNCIL,

MICHIGAN ENVIRONMENTAL COUNCIL,

AND SIERRA CLUB

Resource Insight, Inc.

AUGUST 29, 2017

I. Introduction and Summary

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

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

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit NRD-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have sponsored expert testimony in more than eighty state, provincial, and federal proceedings in the U.S. and Canada, including in Michigan in

Case No. U-17429. I include a detailed list of my previous testimony in Exhibit NRD-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Natural Resources Defense Council ("NRDC"), Michigan Environmental Council ("MEC"), and Sierra Club ("SC").

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring the following exhibits:

- Exhibit NRD-1: Resume of Jonathan Wallach, Resource Insight, Inc.
- Exhibit NRD-2: Citations to Marginal-Price Elasticity Studies
- Exhibit NRD-3: DTE Response to MECNRDCSCDE-1.26a
- Exhibit NRD-4: DTE Response to MEDNRDCSCDE-1.27

Q: What is the purpose of your testimony?

A: On April 19, 2017, DTE Electric Company ("DTE" or "the Company") filed an application for authority to increase electric rates, including supporting testimony by Thomas W. Lacey and Michael A. Williams regarding the Company's proposal to increase the monthly service charge for residential customers from $7.50 to $9.00 per customer. My testimony responds to the testimony by Mr. Lacey and Mr. Williams with respect to the residential service charge.

Q: Please summarize your findings and conclusions regarding the Company's proposal to increase the residential service charge.

A: While I am not a lawyer, it is my understanding that in the previous two rate cases the Commission rejected the Company's proposals to increase the residential service charge because the proposed charges would exceed "the marginal costs associated with attaching a customer to the system."[1] In the current proceeding, DTE again proposes to set the residential service charge at a rate that exceeds marginal connection costs. Consequently, as discussed in more detail below, the proposed increase would:

- Inappropriately shift recovery of load-related costs to the residential charge.
- Lead to subsidization of high-usage residential customers' costs by low-usage customers, and thereby inequitably increase bills for the Company's smallest residential customers.
- Dampen price signals to consumers for reducing energy usage.

In contrast, the current residential service charge reasonably reflects the marginal cost to connect a residential customer. Accordingly, as in Case Nos. U-17767 and U-18014, the Commission should again reject the Company's proposal to set the residential service charge at a rate that exceeds marginal cost. Instead, the residential service charge should continue at its current rate.

II. DTE Proposal

Q: What is the Company's proposal with respect to the residential service charge?

A: The Company proposes to increase the residential service charge from $7.50 to $9.00 per customer per month. The proposed $1.50 increase represents a 20% increase over the current service charge.

[1] Commission Order in Case No. U-17767 (December 11, 2015), p 119 and Commission Order in Case U-18014 (January 31, 2017), p. 107.

Company witness Williams contends that the Company's proposal would result in a residential service charge that better reflects the fixed customer-related cost to serve the residential class, as indicated by the results of the unbundled cost of service study for the test year ending October 31, 2018 ("2018 UCOS"):

> These revised service charges will recover a greater portion of the residential customer related costs, as supported by the Company's cost of service study. Witness Lacey's testimony and his Exhibit A-13, Schedule F1.3 supports residential customer related fixed distribution costs that do not vary with energy (kWh) consumption of over $44 per customer per month, but in the interest of gradualism, the Company is proposing only a $9.00 residential service charge in this case.[2]

Q: Does the 2018 UCOS indicate that residential customer-related costs amount to more than $44 per customer per month, as Mr. Williams contends?

A: No. Mr. Williams mischaracterizes the results of the 2018 UCOS. According to Company witness Lacey, the amount derived in the 2018 UCOS for residential "customer charge costs" ($44.46 per customer per month) was calculated "using *all* fixed distribution costs (demand plus customer)."[3] In fact, of the total $44.46 amount derived in the 2018 UCOS, only $8.26 is customer-related.[4]

In other words, 2018 test year embedded costs classified as customer-related and allocated to the residential class in the 2018 UCOS amount to

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[2] *Qualifications and Direct Testimony of Michael A. Williams*, Case No. U-18255, MAW-9 (April 19, 2017) [hereinafter "Williams Direct"].

[3] *Qualifications and Direct Testimony of Thomas W. Lacey*, Case No. U-18255, TWL-21 (April 19, 2017) [hereinafter "Lacey Direct"]. Emphasis added.

[4] DTE response to Question No. MECNRDCSCDE-1.26a, which I am sponsoring as Exhibit NRD-3.

$8.26 per customer per month. Thus, the residential service charge of $9.00 per customer per month proposed by DTE would recover more than 100% of residential customer-related costs, not just a portion as Mr. Williams contends. The additional $0.74 over customer-related costs are demand-related costs that DTE seeks to recover through the residential service charge under the Company's proposal.

Q: Why does the 2018 UCOS include both customer-related and demand-related distribution costs in the calculation of residential "customer charge costs"?

A: The Company includes all distribution costs in the 2018 UCOS calculation of residential customer charge costs because DTE believes that all such costs should be recovered through the residential service charge. According to Mr. Lacey:

> Demand-related costs are fixed costs…. Cost causation should match cost recovery as much as possible; therefore, all fixed costs, demand and customer related, should be collected through the fixed customer charge.[5]

Mr. Lacey supports his argument for collecting all distribution costs through the residential service charge by noting that a study by the Brattle Group reported that "Omaha Public Power District will collect 100% of its fixed distribution costs in its customer charge by 2019."[6] However, Mr. Lacey misinterprets the findings of the Brattle Group study. This study reports that the Omaha Public Power District will collect 100% of *customer-*

[5] Lacey Direct, TWL-23.

[6] *Id.*

related distribution costs, not 100% of *all* distribution costs as Mr. Lacey contends.[7]

Q: Do you agree with the Company's assertion that demand-related costs are fixed and therefore appropriately recovered through the residential service charge?

A: No. Such costs may appear "fixed" from the short-term perspective of utility accounting treatment since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load or sales in that year. However, from the longer-term perspective of cost-causation and economic efficiency, distribution plant and operations and maintenance ("O&M") costs are variable with respect to customer usage and therefore avoidable by reducing customer usage.

Shifting recovery of demand-related distribution costs from the energy charge to the service charge would affect residential customers in two ways. First, it would result in subsidization of high-usage residential customers' costs by low-usage customers. Second, it would dampen price signals and thereby discourage economically efficient behavior by residential customers.

I address each of these effects in the following two sections.

III. Intra-Class Cost Subsidization

Q: How would the Company's proposal to increase the residential service charge cause intra-class subsidization?

[7] The Brattle Group study was provided in the Company's response to Question No. MECNRDCSCDE-1.27, which I am sponsoring as Exhibit NRD-4.

A: As discussed above in Section II, DTE's proposal to increase the residential service charge would shift recovery of demand-related costs from the energy charge to the service charge. Such demand-related costs are driven by residential load and are therefore appropriately recovered from residential customers in proportion to their contribution to total load. To the extent that demand-related costs are recovered at a fixed rate through the residential service charge rather than at a volumetric rate through the energy charge, residential customers with below-average usage would bear a disproportionate share of demand-related costs and consequently subsidize larger customers. In this case, a residential customer with below-average usage will pay more, and a residential customer with above average-usage will pay less, than their fair share of such costs.

Q: What would be the annual amount of demand-related costs recovered through residential service charge under the Company's proposal to increase the residential service charge to $9.00?

A: As discussed above in Section II, the proposed $9.00 residential service charge would recover $0.74 of demand-related costs from each residential customer every month. The 2018 UCOS assumes about 1.98 million residential customers in the test year, which means that about $17.6 million of demand-related costs would be recovered annually through the service charge under DTE's proposal.[8]

Q: What is the extent of the intra-class subsidization under the Company's proposal to increase the residential service charge?

[8] Exhibit A-13, Schedule F1.3, 5.

A: If the demand-related costs recovered through the residential service charge under the Company's proposal were instead recovered through the energy charge, each residential customer would contribute to recovery of these costs in proportion to their usage. Specifically, the 2018 UCOS assumes residential sales in the test year of about 14.6 million megawatt-hours, which means that the $17.6 million of demand-related costs that would be recovered through the service charge under DTE's proposal would be charged at a rate of $1.21/MWh if such costs continued to be recovered through the energy charge.[9] In that case, a residential customer with monthly usage of 200 kWh would contribute about $2.90 per year toward recovery of such costs while a customer with monthly usage of 1,000 kWh would contribute $14.52 per year. Thus, the 1,000 kWh customer would contribute five times more than the 200 kWh customer, in direct proportion to their usage.

In contrast, under the Company's proposal, each residential customer would contribute $8.89 per year toward recovery of the $17.6 million of demand-related costs regardless of that customer's usage. A 200 kWh customer would therefore pay several times more than her fair share under the Company's proposal while a 1,000 kWh customer would pay about 60% of her fair share.

IV. Economically Efficient Price Signals

Q: How would the Company's proposal to increase the residential service charge dampen price signals?

[9] *Id.*

A: As discussed below, DTE proposes to set the residential service charge at a rate that exceeds the marginal cost to connect a residential customer. Consequently, the energy charge will understate the extent to which the Company's costs are driven by customer usage, which will dampen price signals for energy efficiency.

Q: How should residential energy and customer charges be designed in order to provide price signals for efficient customer behavior?

A: Customer charges are intended to recognize that all customers contribute to the cost of distribution service regardless of the customer's energy usage, whereas energy charges recognize that customers of different sizes and load profiles contribute to distribution service costs at different levels. If usage-driven costs are inappropriately collected through fixed customer charges, then customers will have reduced incentives to maximize their energy efficiency.

Accordingly, energy charges should be set at levels that recover costs that tend to increase with customer usage. Energy charges should include costs directly driven by customer usage, such as distribution plant costs, operation and maintenance ("O&M") costs, and any other costs directly related to maintaining reliability of an expanding distribution system. They should also include costs that tend to rise indirectly with customer usage level, such as collection costs, uncollectible costs, and some other customer-service costs.

In contrast, the customer charge is intended to reflect the cost to connect to the distribution system a customer who uses very little or zero energy.[10]

[10] *See, e.g.,* Jim Lazar & Wilson Gonzalez, Smart Rate Design for a Smart Future, Regulatory Assistance Project, 36 (July 2015).

Such "marginal connection costs" are generally limited to plant and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses.[11]

Q: What is the marginal cost to connect a residential customer in the Company's service territory?

A: As discussed in Section II, DTE estimates a connection cost for a residential customer with a dedicated service drop of $8.26 per customer per month. Based on the data provided in Exhibit A-13, Schedule F1.3, I estimate a connection cost of $6.96 per customer per month for a residential customer that does not require a service drop, such as a small customer in multi-family housing. I derived the monthly connection cost of $6.96 per customer by netting the annual amount for residential overhead and underground services costs ($30.9 million) from the annual amount for all residential customer-related costs ($196.4 million) and then dividing that net amount by the number of residential customers (1.98 million) and by 12. Thus, $6.96 = ($196.4-$30.9) / 1.98 / 12.

The current residential service charge falls within the range of marginal connection costs. In contrast, the $9.00 service charge proposed by DTE overstates estimated connection cost by about 9%–29%. The excess over marginal connection cost represents usage-related costs that are appropriately recovered in the energy charge. However, under the Company's proposal, this excess over marginal connection cost would instead be recovered through the service charge. This shift in the recovery of usage-related costs from the

[11] A very small customer in multi-family housing might not require their own service drop. If so, the cost to connect such a customer would not include the cost of a service drop.

energy charge to the service charge would dampen price signals and discourage economically efficient conservation by residential customers.

Q: How does the Company's proposal to increase the residential service charge by $1.50 per month affect the residential energy rate?

A: With the residential service charge set at $9.00, I estimate that the bundled full-service energy rate would increase to 15.14¢/kWh in order to recover the proposed allocation of 2018 test year revenue requirements to D1 customers.[12] If, instead, the service charge remained at its current rate of $7.50, the energy rate would have to be increased to 15.38¢/kWh to recover the same allocated revenue requirement.[13] Thus, the energy rate under the Company's proposal to increase the monthly customer charge by $1.50 would be 0.24¢/kWh, or about 1.6%, less than the energy rate without the proposed increase to the service charge.

Q: To what extent would the lower energy rate under the Company's proposal for the customer charge dampen price signals for conservation?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of thirty-six articles on residential electricity demand published between 1971 and 2000 reports short-run average-rate

[12] Based on data provided in Exhibit A-14, Schedule F3.

[13] *Id.*

elasticity estimates of about −0.35 on average across studies and long-run average-rate elasticity estimates of about −0.85 on average across studies.[14]

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[15] Table 1 lists the results of seven studies of marginal-price elasticity over the last forty years.[16]

Table 1: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 without electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential energy rate?

A: From Table 1, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

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[14] In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in average rates. The citation for this study is provided in Exhibit NRD-2.

[15] For full-service D1 customers, that would be the bundled energy rate.

[16] The citations for these studies are provided in Exhibit NRD-2.

Q: What would be a reasonable estimate of the effect on energy use from a 1.6% reduction to the bundled full-service energy rate under the Company's proposal to increase the residential service charge?

A: An elasticity of –0.3 and a 1.6% reduction in marginal energy price would result in an increase in energy consumption of about 0.5%. This means that all else equal, residential load would be expected to increase by almost 0.5% over a several-year period as a result of implementing the Company's proposed service charge increase.

For comparison, DTE currently forecasts that residential energy sales will decline on average by about 0.3% per year over the next decade.[17] Thus, the consumption increase due to the Company's proposed increase to the residential service charge (and the resulting decrease in the energy charge) would offset almost two years of the forecasted decline in residential energy sales and likely increase costs to all customers.

V. Conclusions and Recommendations

Q: What do you conclude with respect to the Company's proposal to increase the residential service charge to $9.00?

A: Contrary to long-standing Commission practice, DTE proposes to recover more than marginal connection costs through the residential service charge. The Company's proposal would therefore inappropriately shift recovery of usage-related costs from the energy charge to the service charge, unreasonably dampen energy price signals, and discourage conservation by

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[17] *Qualifications and Direct Testimony of Markus B. Leuker*, Case No. U-18255, MBL-15 (April 19, 2017).

residential customers. It would also lead to subsidization of high-usage customers by low-usage customers.

In contrast, the current residential service charge reasonably reflects the marginal cost to connect a residential customer. Accordingly, the Commission should reject the Company's request to increase the residential service charge. Instead, the residential service charge should continue at its current rate.

Q: Does this conclude your direct testimony?

A: Yes.

Qualifications of

JONATHAN F. WALLACH

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

SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

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

EDUCATION

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

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

PUBLICATIONS

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

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

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"Electricity Market Design: Incentives for Efficient Bidding; Opportunities for Gaming." 2002. Silver Spring, Maryland: National Association of State Consumer Advocates.

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

"Comments Regarding Retail Electricity Competition." 2001. Filed by the Maryland Office of People's Counsel in U.S. FTC Docket No. V010003.

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

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

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

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"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Paul Chernick). 1996. Concord, N.H.: NH OCA.

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

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.). 1992.

"Comments on the Utility Responses to Commission's November 27, 1990 Order and Proposed Revisions to the 1991–1992 Annual and Long Range Demand Side Management Plans" (with John Plunkett et al.). 1991.

"Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities" (with John Plunkett et al.). Filed in NY PSC Case No. 28223 in re New York utilities' DSM plans. 1990.

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MPSC Case No.:	U-18255
Respondent:	T. W. Lacey
Requestor:	MECNRDCSC-1
Question No.:	MECNRDCSCDE-1.26a
Page:	1 of 1

Question: Refer to the Direct Testimony of Thomas Lacey, p 21.

a. Identify the portion of the $44.46 in customer charge costs for residential customers that is customer-related and the portion that is demand-related.

Answer: $36.20 is demand-related and based upon Exhibit A-13, Schedule F1.4, $8.26 is customer-related.

MPSC Case No.: U-18255
Respondent: T. W. Lacey
Requestor: MECNRDCSC-1
Question No.: MECNRDCSCDE-1.27
Page: 1 of 1

Question: Refer to lines 16-18 on page 23 of the Direct Testimony of Thomas Lacey. Produce the Brattle Group Survey.

Answer: See the attached PDF file “U-18255 MECNRDCSCDE-1.27 Brattle Group Report”.

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation and Rate Design. (U 39 M)	Application 16-06-013 (Filed June 30, 20116)

BRATTLE GROUP REPORT ON FIXED CHARGES IN RESIDENTIAL TARIFFS SUBMITTED BY PACIFIC GAS AND ELECTRIC COMPANY FOR WORKSHOP ON NOVEMBER 2, 2016

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PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 26, 2016

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OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation and Rate Design. (U 39 M)	Application 16-06-013 (Filed June 30, 20116)

BRATTLE GROUP REPORT ON FIXED CHARGES IN RESIDENTIAL TARIFFS SUBMITTED BY PACIFIC GAS AND ELECTRIC COMPANY FOR WORKSHOP ON NOVEMBER 2, 2016

Pursuant to the Administrative Law Judge's ruling on the residential fixed charge workshops in this proceeding and PG&E's representation at the first such workshop on October 13, 2016, PG&E attaches material for the second workshop on November 2, 2016 that provides benchmarking data on the fixed cost methodologies used by other public utilities commissions and utilities in other jurisdictions. This workshop material consists of the attached report prepared by The Brattle Group entitled "Methodologies for Establishing Fixed Charges in Residential Tariffs: A Survey." PG&E also will provide additional hard copies and information on the report and respond to questions on the Report as appropriate at the November 2, 2016, workshop.

Respectfully submitted,

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By: /s/
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Dated: October 26, 2016

Methodologies for Establishing Fixed Charges in Residential Tariffs: A Survey

PREPARED FOR

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company

PREPARED BY

Ahmad Faruqui, Ph. D.

Kirby Leyshon, B.A.

October 26, 2016

THE Brattle GROUP

This report was prepared for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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Within The Brattle Group, we would like to acknowledge Neil Lessem for his assistance in framing the survey instrument that was used to conduct the research, and Phil Hanser and Sanem Sergici for providing information on the Omaha Public Power District.

Finally, we would like to acknowledge several individuals from around the country who made this report possible. They provided answers to the survey instrument that appears in Appendix A. These individuals are William Atzl (Consolidated Edison), Greg Bollom (Madison Gas & Electric), Scott Brockett (Public Service Company of Colorado), Glynis Bunt (Central Hudson Gas & Electric), Marc Cody (Portland General Electric), Edward A. Davis (Eversource), Glenn Dyke (Georgia Power Corporation), Charles Goodwin (United Illuminating), Wayne Harbaugh (Baltimore Gas & Electric), Alcides Hernandez (Sacramento Municipal Utility District), Mark Marini (Rochester Gas & Electric), Jeff Martin (Westar Energy), Mary M. Murray (DTE Energy), Jimi Netnisss (Modesto Irrigation District), Sarah Noll (Commonwealth Edison), Matt Nollenberger (Indiana Michigan Power Company), Joelle Steward (PacifiCorp), Steve Romig (Florida Power & Light), Bryan Scott (Oklahoma Gas & Electric), and Tami Wallenburg (Turlock Irrigation District).

Table of Contents

Executive Summary

This report surveys the methodology for designing and establishing the levels of fixed charges for residential customers of electricity in the United States. Information is presented on the methodology and application of fixed charges by individual electric utilities located around the country and supported by the corresponding state public utility commissions or other regulatory body.

We reached out to thirty-seven utilities across the country and asked them a series of questions addressing the underlying theory, practical methodology, and implementation of fixed charges. They were also asked to provide written evidentiary testimony and links to regulatory commission decisions and guidance. Thirty-three utilities responded to the survey.[1] Their information is presented in this report along with information on two other municipal utilities in California that was gleaned from the municipal utilities' websites. This document generally reflects information available in Q1 2016 unless otherwise noted.

The surveyed utilities lie in regions that have a similar regulatory environment to California's in terms of the stated goals and public policies supporting energy efficiency and renewable energy resources.[2] The group of utilities that responded to the survey covers four major regions and 23 states. Initially, utilities for the survey were chosen on the basis of having residential fixed charges greater than $5.00/month; however, this list was expanded in order to capture more utilities with similar regulatory environments that may have lower residential fixed charges. The initial survey instrument contained 19 questions. A supplemental survey containing five

[1] These utilities include subsidiaries of major utility companies and utilities that serve multiple regions with separate rates for each region. For example, the survey response for Eversource encompasses Connecticut Light & Power, Public Service Company of New Hampshire, and Western Massachusetts Electric Company.

[2] For example, New York's Reforming the Energy Vision ("REV") initiative which includes a NY State Energy Plan proposes three statewide clean energy targets to be completed by 2030 including reducing greenhouse emissions by 40% from 1990 levels, generating 50% of electricity from renewable energy sources, and increasing statewide energy efficiency by 600 trillion British thermal units. "The Energy to Lead," *New York State Energy Plan Volume 1*, 2015, pp. 44-45, https://static1.squarespace.com/static/576aad8437c5810820465107/t/5797fc52f5e231d942a2d79b/1469578322990/2015-state-energy-plan-pf.pdf.

additional questions was also submitted to each responding utility (reproduced in Appendix A). Survey responses were compiled in a database, collated by region and presented in this report.[3]

As evidenced by the utility responses presented in this report, fixed charges are routinely applied by investor-owned utilities in other states and also applied by municipal utilities in California. Indeed, several utilities have had fixed charges for decades.

Many of the utilities identified have approved residential fixed charges that exceed California's statutory limit of $10.00/month (adjusted by the Consumer Price Index) for investor-owned utilities. In addition, several utilities also identified residential fixed costs in excess of $10.00/month. In other states, and in California's municipal utilities, fixed charges are also routinely adjusted upward to reflect changes in fixed costs and changes in the utility business environment.

Several state utility commissions distinctly mention fixed charges in their final decisions as a means of aligning fixed costs with revenues and cost causation. Some go a step further to suggest that over time, fixed charges should be moved closer to total fixed costs, including costs that do not vary with the volume of electricity consumed, as determined by utilities' cost of service studies. Notably, the survey reveals that the presence of decoupling does not eliminate support for fixed charges.

Only four out of the 37 utilities surveyed differentiate their fixed charges based on the size of the customer or by the type of the customers dwelling. Some utilities offer a lower fixed charge to low-income customers or alternatively offer a fixed credit to low-income customers which could be characterized as simply providing a lower fixed charge to low-income customers. Only one utility in the survey uses the fixed charge revenues to reduce the revenues collected in the first tier rates exclusively in an inclining block rate structure. Some utilities indicate that they design

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[3] Information that does not have a direct citation in the summaries below was provided by the utility in the survey response and a corresponding document may not have been included. In many cases, information drawn from the survey is drawn verbatim. All cited documentation, as well as additional documentation regarding each fixed charge, is included in Appendix B. Additionally, in order to identify utilities whose revenues are subject to decoupling and whose rates are set in reliance on marginal (as opposed to embedded) costs, a " D " is included next to the utility headings for utilities that use decoupling and an " M " is included next to the utility headings for utilities that use marginal costs.

their fixed charges based on customer-related fixed costs, which are defined as the costs of the meter, service drop, a portion of the transformer, billing, and customer service unless otherwise specified. A summary of the results appears in Table 1 and Table 2. Care should be taken when reviewing the "Percentage of Fixed Costs recovered through Fixed Charges" column. Depending on how each utility defines their fixed costs (see the detailed text for each utility), the self-reported percentages will be very different. For example, if a utility includes a portion of the distribution grid as a fixed cost, the reported percentage of fixed costs recovered via fixed charges will generally be lower. Conversely, if a utility narrowly defines fixed costs to only include traditional customer-related fixed costs, then the reported percentage of fixed costs recovered via fixed charges will generally be higher.

Table 1: A Summary of Fixed Charges in Residential Tariffs

	What cost categories are included in fixed costs?
NORTHEAST & MIDDLE ATLANTIC	
Baltimore Gas & Electric	Metering, meter reading, billing and collections, customer care, and service connection.
Central Hudson Gas & Electric	Metering, billing, and customer care.
Consolidated Edison Company	Overhead and underground service connections, metering equipment, meter reading and maintenance, meter installations, customer service, customer accounting, uncollectibles, and minimum system costs which include a portion of fixed costs for transformers and secondary distribution lines.
Rochester Gas and Electric	Meters, service drop, meter reading and billing, distribution substation and trunkline feeder costs, upstream line and substation costs, and marginal transmission costs.
New York State Electric Gas Corporation	Meters, service drop, meter reading and billing, distribution substation and trunkline feeder costs, upstream line and substation costs, and marginal transmission costs.
Central Maine Power	Meters, service drop, meter reading and billing, distribution substation and trunkline feeder costs, upstream line and substation costs, and marginal transmission costs.
Eversource Energy	
Connecticut Light & Power	Meters and services, meter reading, customer records and collection, customer service, additional overhead expenses that may be allocated and included in customer-related costs, and minimum system cost components such as service transformers, lines, and poles.
Public Service Company of New Hampshire	Meters and services, meter reading, customer records and collection, customer service, additional overhead expenses that may be allocated and included in customer-related costs, and minimum system cost components such as service transformers, lines, and poles.
Western Massachusetts Electric Company	Meters and services, meter reading, customer records and collection, customer service, and additional overhead expenses that may be allocated and included in customer-related costs.
United Illuminating Company	Metering, billing, customer care, service lines, transformers, and a portion of allocated poles and wires.
MIDWEST & SOUTH	
Commonwealth Edison	Services, customer installations, billing, indirect uncollectibles, customer information, and revenue-related customer costs.
DTE Energy	Metering, overhead and underground services, customer records and collection, and customer service expenses.
Indiana Michigan Power Company	
Indiana Michigan - Indiana	Distribution costs such as metering costs, customer account and service expenses, general and administrative expenses, depreciation, and taxes.
Indiana Michigan - Michigan	Distribution costs such as metering costs, customer account and service expenses, general and administrative expenses, depreciation, and taxes.
Madison Gas & Electric	Costs of customer accounts and services, a portion of allocated administrative and general expenses, general and common plant depreciation and return, and taxes, distribution plant depreciation and return, and operating and maintenance expenses.
Oklahoma Gas & Electric	Customer billing, administration, metering, service drop, and a portion of the transformer, lines, and poles.
Omaha Public Power District	Customer-related fixed costs including customer-related distribution system fixed costs.
Westar Energy	Meters, billing, meter reading, service lines, and a portion of distribution.
Florida Light & Power	Pull-offs, installations on customer premises, meters, service drops, and customer collections, services, and sales costs.
Georgia Power	Metering and billing and cost components of the minimum distribution system such as poles, overhead conductors, underground conduits, conductors and devices, and line transformers.
WEST OTHER THAN CALIFORNIA	
PacifiCorp	
Rocky Mountain Power - Utah	Customer-related customer service and distribution costs.
Rocky Mountain Power - Wyoming	Customer service and distribution costs.
Rocky Mountain Power - Idaho	Customer service and distribution costs.
Pacific Power & Light - Washington	Customer-related customer service and distribution costs.
Pacific Power & Light - Oregon	Customer service and distribution costs.
Pacific Power & Light - California	Customer service and distribution costs.
Portland General Electric	Customer service costs, uncollectibles, and the customer-related portion of the service lateral and transformer.
Public Service Company of Colorado	Investment costs of meters and service drops, meter reading, customer service and billing expenses, and some allocated overhead costs.
CALIFORNIA	
Glendale Water & Power	*
Modesto Irrigation District	Customer-related expenses.
Riverside Public Utilities	Meter reading, billing, customer service and administration, and debt service related costs.
Sacramento Municipal Utility District	Cost of metering, billing, customer services, transformers, poles, wires, and other electric equipment used to provide reliable electric service.
Turlock Irrigation District	Billing and collection, meter reading, service drops, final line transformers, general and administrative expenses, and other related expenses.

Notes: *Response or specific information not available.

Table 2: A Summary of Fixed Charges in Residential Tariffs

	Size of General Residential Fixed Charge	Percentage of Fixed Costs Recovered Through Fixed Charge	Cost Studies Used for Class Revenue Allocation and Rate Design	Fixed Charges for Non-Residential Customers	Decoupling	Marginal Cost	Capacity or Demand-Related Costs Included in Fixed Charge	Difference in Fixed Charge for Type of Customer Dwelling or Size of the Customer	Low-Income Customer Fixed Charge Discount or Bill Credit	Fixed Charges to Reduce Tier 1 Rates
NORTHEAST & MIDDLE ATLANTIC										
Baltimore Gas & Electric	$7.90	45%	X	X	X				X	
Central Hudson Gas & Electric	$24.00	69%	X	X	X				X	
Consolidated Edison Company	$15.76	77%	X	X	X				X	
Rochester Gas and Electric	$22.10	47%		X	X	X	X	X		
New York State Electric Gas Corporation	$15.92	39%		X	X	X	X			
Central Maine Power	$12.88	23%	X	X	X	X	X			
Eversource Energy										
Connecticut Light & Power	$19.25 - $23.75	*	X	X	X		X			
Public Service Company of New Hampshire	$12.75	*	X	X			X			
Western Massachusetts Electric Company	$6.00	*	X	X	X				X	
United Illuminating Company	$17.25	*	X	X	X		X			
MIDWEST & SOUTH										
Commonwealth Edison	$13.35 - $17.66	40%	X	X				X		
DTE Energy	$6.00	25%	X	X					X	
Indiana Michigan Power Company										
Indiana Michigan - Indiana	$7.30	100%	X	X						
Indiana Michigan - Michigan	$7.25	100%	X	X						
Madison Gas & Electric	$19.00	88%	X	X			X			
Oklahoma Gas & Electric	$13.00	*	X	X					X	
Omaha Public Power District	$15.00	100%	X	X					X	
Westar Energy	$14.50	14%	X	X						
Florida Light & Power	$7.87	26%	X	X			X			
Georgia Power	$10.00	50%	X	X					X	
WEST OTHER THAN CALIFORNIA										
PacifiCorp										
Rocky Mountain Power - Utah	$6.00 - $12.00	*	X	X				X		
Rocky Mountain Power - Wyoming	$20.00	*	X	X			X			
Rocky Mountain Power - Idaho	$5.00	*	X	X			X			
Pacific Power & Light - Washington	$7.75	28%	X	X					X	
Pacific Power & Light - Oregon	$9.50	*	X	X		X	X			
Pacific Power & Light - California	$7.07	*	X	X		X	X		X	
Portland General Electric	$10.50	49%	X	X	X	X				
Public Service Company of Colorado	$7.71	100%	X	X						
CALIFORNIA										
Glendale Water & Power	$11.00	*	*	X		*	*		X	*
Modesto Irrigation District	$20.00	*	X	X					X	X
Riverside Public Utilities	$8.06	*	*	X		*		X		
Sacramento Municipal Utility District	$18.00	75%	X	X		X			X	
Turlock Irrigation District	$17.00	*	*	X					X	*

Notes: *Response or specific information not available.

Fixed Charges by Region

I. Northeast and Middle Atlantic

A. Baltimore Gas & Electric Company [D]

Maryland, Maryland Public Service Commission

Baltimore Gas and Electric's ("BG&E") fixed charges are designed to collect the fixed costs of metering, meter reading, billing and collections, customer care, and the service connection. These fixed costs are estimated using the embedded cost methodology. BG&E uses an electric cost of service study ("ECOSS") for class revenue allocation and rate design. The utility states that the ECOSS "is developed to allocate costs to individual classes then 'match' distribution revenues from each rate class with rate base and expenses allocated to the given class."[4] The utility defines classes for revenue allocation using the ECOSS generally based on the utility's tariff rate classes where some like classes are combined.[5] The utility uses the same methodology to collect fixed costs from residential and non-residential customers.

There are two residential customer rate schedules: the residential service schedule and the residential optional time-of-use ("TOU") schedule. The general residential service fixed charge is $7.90/month[6] and the residential optional TOU fixed charge is $12.00/month.[7] A state-mandated Electric Universal Service Program provides bill assistance to low-income residential BG&E customers. The funding for this program comes from surcharges placed on non-low income customer bills, which the utility applies as credits to low-income customer bills. For general residential service customers, the current level of the fixed customer charge recovers approximately 45 percent of fixed costs.

In its recent Smart Grid case before the Maryland Public Service Commission ("MPSC") filed in November 2015, the utility proposed increasing the general residential service fixed charge to

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[4] Maryland Public Service Commission, *Prepared Direct Testimony of David E. Greenberg on Behalf of Baltimore Gas and Electric Company*, Case No. 9406, November 6, 2015, p. 15.

[5] *Id.*, pp. 27-29, Exhibit DEG-2.

[6] "Residential Service-Electric Schedule R," Baltimore Gas and Electric Company, effective June 4, 2016, accessed October 23, 2016, https://www.bge.com/MyAccount/MyBillUsage/Documents/Electric/P3_SCH_R.pdf.

[7] "Residential Optional Time-of-Use – Electric Schedule RL," Baltimore Gas and Electric Company, effective June 4, 2016, accessed October 23, 2016, https://www.bge.com/MyAccount/MyBillUsage/Documents/Electric/P3_SCH_RL.pdf.

$12.00/month to match the residential optional TOU fixed charge.[8] BG&E's testimony explains that, with the installation of smart meters, the difference in service costs between general residential service and residential optional TOU service will not be substantially different as both groups of residential customers will be using the same meter.[9] Unless a customer decides not to receive a Smart Meter, there is no difference in customers who can be served under either schedule. The ECOSS presented in this rate case indicates that the full costs for both the general residential service class and residential optional TOU class are approximately $16.00/month.[10] The testimony supports that an increase in residential fixed charges will bring cost recovery closer to ECOSS levels. MPSC Staff recommended a more gradual increase to $7.90/month on the basis that limiting the fixed charge increase "provides customers more control over their bills and promotes policy goals of energy efficiency as outlined in the EmPOWER Maryland Act."[11] On June 3, 2016, the MPSC accepted the Staff's recommendation and granted an increase in the general residential service fixed charge from $7.50/month to $7.90/month effective June 4, 2016.[12] This increase maintains the same proportion of fixed to variable rate revenue from the residential fixed charge of 19.4 percent.[13]

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[8] Maryland Public Service Commission, *Prepared Direct Testimony of John C. Frain on Behalf of Baltimore Gas and Electric Company*, Case No. 9406, November 6, 2015, pp. 12-14.

[9] *Ibid.*

[10] *Ibid.*

[11] Maryland Public Service Commission, *Order No. 87591*, Case No. 9406, June 3, 2016, pp. 190-191, http://www.psc.state.md.us/wp-content/uploads/Order-No.-87591-Case-No.-9406-BGE-Rate-Case.pdf.

[12] *Id.*, pp. 192-193.

[13] *Ibid.*

B. Central Hudson Gas & Electric D
New York, New York Public Service Commission

Central Hudson's fixed charge seeks to collect fixed costs for metering, billing, and customer care as well as the customer portion of primary and secondary lines, transformers and services. These fixed costs are based on an ECOSS that takes into account projected costs of the future rate year. The ECOSS is used for both class revenue allocation and rate design. Central Hudson defines the classes for revenue allocation on various levels. Classes are first defined as residential, non-residential, or lighting (un-metered). Residential classes are separated into general service or TOU, non-residential customer classes are defined based on service level, and lighting classes are defined by type.[14] The utility indicates that for residential customers, non-demand fixed charges are typically set lower than the fixed costs allocated to the residential class in the ECOSS. Revenues and sales are decoupled for residential and some non-residential classes. The decoupling mechanism includes fixed charges as it is calculated using revenue per customer class.

There are different fixed charges for general service and TOU service for residential customers as well as an income-based discount which is provided through a separate program.[15] General residential customers have a fixed customer charge of $24.00/month while TOU residential customers have a fixed customer charge of $27.00/month.[16] In order to maintain the current level of fixed charges as determined in the last rate case described below, Central Hudson collects fixed charges in excess of the fixed costs for certain customer classes.[17] These classes typically have fixed charges with a smaller proportion of total costs that are fixed, less than 22 percent. The proportion of total fixed costs that are included in fixed charges for residential and non-demand customers (the utilities' most populous classes) are much greater, from 50 to 68 percent. Sixty-nine percent of fixed costs are recovered through fixed charges for standard residential customers and 54 percent are recovered for TOU residential customers.

Since 2001, when Central Hudson unbundled delivery and supply components, the utility's general residential service customer class fixed charges have increased by 236 percent as the

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[14] Lighting includes area lighting, street lighting, and traffic signals.

[15] The low-income program offers discounted monthly budget bills, arrears forgiveness, and bill credits.

[16] "Delivery Rate Summary," Central Hudson, effective July 1, 2015, July 1, 2016 and July 1, 2017, pp. 5-6, http://www.centralhudson.com/pdf/deliveryratesummary.pdf.

[17] These customer classes include Non-Residential - Non-Demand, Non-Residential - Primary Demand >= 1 MW, Non-Residential - Substation, Non-Residential – Transmission, Lighting – Area, Lighting – Street & Highway, and Lighting – Traffic Signal.

utility continues to propose the alignment of fixed charges with recovery of fixed costs. In the last rate case, in which the utility proposed a three-year rate plan from July 2015 to June 2018, the New York Public Service Commission ("NYPSC") rejected a $5.00/month increase in the residential fixed charge and required that the utility maintain the customer charge at $24.00/month, where it is currently.[18] The NYPSC stated that they rejected the increase in fixed charges because the REV initiative in New York is likely to impact rates before the end of the three-year rate plan.[19] Therefore, it would be logical to avoid making tariff changes that would potentially change again in the near future. However, the NYSPC also stated that "it is appropriate in the rate design in this case to rely on the ECOSS study and familiar cost of service principles as a guide for the apportionment of the electric revenue requirement increases between fixed and volumetric charges."[20]

[18] New York Public Service Commission, *Order Approving Rate Plan*, Case No. 14-E-0318, June 17, 2015, p. 56-58, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FBCE2FF2-61D7-47A9-9956-773EFC20944A}.

[19] In the REV proceedings regarding the adoption of a ratemaking and utility revenue model policy framework, the NYPSC stated rate design principles which indicate that "Rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs. Fixed charges should only be used to recover costs that do not vary with demand or energy use." New York Public Service Commission, *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*, Case No. 14-M-0101, May 19, 2016.

[20] New York Public Service Commission, *Order Approving Rate Plan*, Case No. 14-E-0318, June 17, 2015, p. 57, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FBCE2FF2-61D7-47A9-9956-773EFC20944A}.

C. Consolidated Edison Company [D]
New York, New York Public Service Commission

Consolidated Edison's ("ConEd") fixed charges are designed to recover costs including overhead and underground service connections, metering equipment, meter reading and maintenance, meter installations, customer service, customer accounting, uncollectibles, and minimum system costs which include a portion of fixed costs for transformers and secondary distribution lines. ConEd estimates fixed customer costs using embedded costs and the utility uses the same ECOSS for class revenue allocation and rate design. Revenue allocation in the ECOSS is developed using service classifications defined in ConEd's tariffs with subcategories in certain service classifications. ConEd indicates that costs are assigned to customer classes by allocating the costs of various functions as follows: transmission costs are allocated based on coincident peak, high tension costs are allocated based on non-coincident peak, low tension costs are allocated based on a combination of non-coincident peak and individual customer maximum demands, and customer-related costs are allocated based on the number of customers. ConEd indicates that there have been no issues in recovering fixed charges from customers subject to the revenue decoupling mechanism ("RDM"). Fixed costs for residential and small non-residential customers are recovered through fixed charges. ConEd functionalizes joint costs such as common plant based on labor.[21] ConEd states that once these costs are part of any functional category in the ECOSS, they are allocated to service classes based on each function's respective allocator. Residential customers are subject to a tiered rate mechanism in the summer months; however, fixed charges do not reduce tier 1 rates exclusively.

Customer charges differ between the TOU and non-TOU residential schedules. Additionally, low-income customers receive a discount on their fixed customer charge. General residential customers have a fixed charge of $15.76/month, TOU residential customers of $19.87/month, and low-income customers of $6.26/month.[22] The general service residential customer charge recovers 77 percent of residential fixed customer costs. ConEd's last rate case, decided in February 2014, did not result in any changes in residential fixed charges with the exception of an increased discount for low-income customers of $9.50/month applied to the fixed customer charge.[23] ConEd filed a new rate case on January 29, 2016.[24] The associated Demand Analysis and

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[21] Common Plant includes vehicles, furniture, computer equipment, and other similar fixtures.

[22] "Service Classification No. 1," Consolidated Edison Company of New York, effective January 1, 2015, Leafs 387-295, http://www.coned.com/documents/elecPSC10/SCs.pdf.

[23] New York Public Service Commission, *Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal*, Case No. 13-E-0030, February 21, 2014, p. 51,

Continued on next page

Cost of Service ("DAC") Panel testimony states that the utility has reevaluated their cost of service methodologies.[25] In particular, ConEd has introduced a "customer component of the High Tension Primary Distribution system" into their customer costs in the ECOSS.[26] Previously, components of the high tension primary distribution system were classified as demand-related.[27] The high tension primary distribution system includes poles, towers, fixtures, overhead conductors, underground conduit, underground conductors, and line transformers.[28] The utility also indicated that the NYPSC has adopted the proposed requirement that NYSEG and RG&E classify distribution plant fifty-fifty as demand- and customer-related in their next rate cases.[29] ConEd's testimony explains that "the Company is paralleling its methodology applied to secondary distribution assets and is also recognizing the increased emphasis on fixed-cost recovery."[30] ConEd did not propose an increase in residential fixed charges in their pending rate case, due in part to the most recent NYPSC decision for Central Hudson regarding the upcoming rate re-examination as part of the REV.[31]

Continued from previous page
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}.

24 "Con Edison 2016 Electric Rate Case Filing," Con Edison, accessed March 3, 2016, https://www.coned.com/2016-rate-filing/2016-rate-filings.asp.

25 Consolidated Edison Company on New York, Inc., *Demand Analysis and Cost of Service Panel Direct Testimony*, January 29, 2016, pp. 17-18, https://www.coned.com/2016-rate-filing/pdf/testimony-exhibits-electric/17-dac-panel-testimony-final.pdf.

26 *Id.*, p. 17.

27 *Ibid.*

28 Consolidated Edison Company on New York, Inc., *Demand Analysis and Cost of Service Panel Direct Testimony – Exhibit_(DAC-1) Schedule 1*, January 29, 2016, pp. 21-23, https://www.coned.com/2016-rate-filing/pdf/testimony-exhibits-electric/16-dac-panel-exhibits-dac-1-dac-3.pdf.

29 Consolidated Edison Company on New York, Inc., *Demand Analysis and Cost of Service Panel Direct Testimony*, January 29, 2016, p. 18, https://www.coned.com/2016-rate-filing/pdf/testimony-exhibits-electric/17-dac-panel-testimony-final.pdf.

30 *Ibid.*

31 Consolidated Edison Company of New York, Inc., *Direct Testimony – Electric Rate Panel*, January 29, 2016, pp. 24-26, https://www.coned.com/2016-rate-filing/pdf/testimony-exhibits-electric/17-dac-panel-testimony-final.pdf.

D. Rochester Gas and Electric DM
New York State Electric Gas Corporation DM
New York, New York Public Service Commission
Central Maine Power DM
Maine, Maine Public Utilities Commission

The three utilities, Rochester Gas & Electric ("RG&E"), New York State Electric Gas Corporation ("NYSEG"), and Central Maine Power ("CMP"), collectively serve customers in both New York and Maine. Their fixed charges are designed to collect customer-related costs and local distribution facilities costs. The utilities indicate that the local distribution facilities costs are based on the expected design load of the customer. Even with the inclusion of local distribution facilities costs in fixed charges, the current monthly fixed charges are lower than what the cost of service study suggests are the fixed costs for most customer classes. NYSEG, RG&E, and CMP own transmission and distribution plants and systems but do not own any generation facilities.[32]

The utilities use marginal cost of service studies ("MCOSS") to support residential fixed charges. The studies identify costs in three categories: customer-related costs, design-demand related costs, and load-related distribution costs. The utilities define customer-related costs as costs that vary with the number of customers on the system. These costs include meters, service drop, meter reading and billing. Design-demand related costs include local facilities costs such as line transformers, secondary lines, and local primary lines. Load-related distribution costs include the distribution substation and trunkline feeder costs, upstream line and substation costs, and marginal transmission costs. Customer-related costs and design-demand-related costs are included in fixed costs associated with the fixed charge, as discussed above. The three utilities have fixed charges for both residential and non-residential customers.

At RG&E and NYSEG, ECOSS are used to guide class allocation of revenue, while MCOSS are used for rate design. At CMP, MCOSS are used for both class revenue allocation and rate design. If marginal costs are used for revenue allocation purposes, then an Equal Percentage Marginal Costs ("EPMC") model is used to scale to the total revenue requirement. The customer classes for

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[32] "NYSEG and RG&E Play Vital Role in the Developing New Power Generation Sources, Including Renewables," RG&E new release, 2011, accessed February 20, 2016. http://www.rge.com/OurCompany/News/2011/interconnections12011.html; "CMP Transmission Service," Central Maine Power, accessed February 20, 2016, http://www.cmpco.com/SuppliersAndPartners/TransmissionServices/CMPTransmissionSvc/default.html; "System Information Overview," Central Maine Power, accessed February 20, 2016, http://www.cmpco.com/SuppliersAndPartners/TransmissionServices/CMPTransmissionSvc/CMPSystemInfo.html.

revenue allocation are defined in the utilities' tariffs. The fixed costs are determined on a per-customer basis, using forward-looking costs to determine the marginal cost associated with serving an additional customer added to the system. The utilities do not follow the methodology of deriving fixed charges solely from customer-related costs. Since smart meters are not in place and because of the desire to keep rates simple, the utility combines both customer-related and design-demand-related costs in the fixed charges. The utilities have used this approach in rate design and rate cases for many years. The utilities have made consistent proposals aimed at increasing fixed and demand charges and reducing energy charges for delivery service.

Decoupling exists in both Maine and New York and is set by total service class revenue so there are no specific issues with respect to collecting fixed charges. Regarding annualized costs, the utilities' investments are annualized using an economic carrying charge which produces a stream of payments[33] and yields the total present value of all costs over the life of the investment.

The current residential fixed charges for NYSEG are $15.11/month for residential service, $17.40/month for residential day/night service,[34] and $24.11/month for residential TOU service.[35] There is also an additional fixed Bill Issuance Charge of $0.81/month for each of the residential service classes.[36] RG&E has a residential fixed charge of $21.38 and two TOU residential fixed charges of either $21.38 (<24,750 kwh/year) or $24.86 (>24,750 kwh/year).[37] There is also an additional fixed Bill Issuance Charge of $0.72/month for each of the residential service classes.[38] CMP has a residential fixed charge of $12.88/month for the first 50 kWh or less[39] and a

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33 These payments increase at the rate of inflation net technical progress.

34 Residential day/night service is applicable to customers who use at least 1,000 kWh of electricity per month with 20 percent of the energy usage occurring during nighttime service hours. During nighttime service hours, 11:30pm to 7am, NYSEG sells electricity at a lower price to residential customers. "Day-Night Service Rate," NYSEG, accessed October 24, 2016, http://www.nyseg.com/yourhome/pricingandrates/daynighrate.html.

35 "Electric Rates Summary," NYSEG, effective September 1, 2016, http://www.nyseg.com/MediaLibrary/2/5/Content%20Management/NYSEG/SuppliersPartners/PDFs%20and%20Docs/N%20Electric%20Rate%20Summary.pdf.

36 *Ibid.*

37 "Electric Rates Summary," RG&E, Effective July 1, 2016, https://www.rge.com/MediaLibrary/2/5/Content%20Management/RGE/SuppliersPartners/PDFs%20and%20Docs/RGE%20Electric%20Rate%20Summary.pdf.

38 *Ibid.*

39 "Rate A Residential Service Electric Delivery Rate Schedule," Central Maine Power Company, effective July 1, 2016,

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residential TOU fixed charge of $10.00/month.[40] The utilities state that they propose fixed charges closer to what is suggested by the MCOSS, but do not propose moving fixed charges to the full amount due to the expected bill impacts on small customers. For standard service residential classes, CMP collects 23 percent of fixed costs through residential fixed charges, NYSEG collects 39 percent, and RG&E collects 47 percent.

In a prior rate case involving NYSEG and RG&E, the NYSPC issued a decision on September 21, 2010 which approved a three-year, four-month rate plan for the two utilities.[41] This rate plan included an increase in residential fixed charges for both of the utilities of $2.00/month in the first year with no other increase in the two remaining years of the plan.[42] This increase was approximately one quarter of the amount the utilities originally proposed.[43] According to NYPSC Staff, the increased customer charge "provide[s] reasonable movement toward the minimum cost to serve."[44] Additionally, as mentioned in the section discussing ConEd, the NYPSC indicated that in the next rate case, the ECOSS for the utilities will classify distribution plant costs fifty-fifty between customer-related and demand-related costs.[45]

The utilities filed a new rate case in May 2015 with a proposal to increase the standard residential fixed charges to $18.89/month for NYSEG and to $26.73/month for RG&E.[46] Subsequent to

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https://www.cmpco.com/MediaLibrary/3/6/Content%20Management/Suppliers%20And%20Partners/PDFs%20and%20Doc/a.pdf.

40 "Rate A-TOU Residential Service – Time-of-Use Electric Delivery Rate Schedule," Central Maine Power Company, effective July 1, 2016, https://www.cmpco.com/MediaLibrary/3/6/Content%20Management/Suppliers%20And%20Partners/PDFs%20and%20Doc/atou.pdf.

41 New York Public Service Commission, *Order Establishing Rate Plan*, Case No. 09-E-0715, September 21, 2010, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4CF18507-1968-4E38-9DB6-FD33FAF8426F}.

42 *Id.*, pp. 47-48.

43 *Id.*, p. 47.

44 *Id.*, p. 47.

45 *Id.*, pp. 45-47.

46 New York Public Service Commission, *Direct Testimony - Revenue Allocation Rate Design Economic Development and Tariff Panel Exhibits*, Case Nos. 15-E-0285 and 15-G-0286, May 20, 2015, Exhibit_(RARDEDT-10), Schedule 1, p. 1, Schedule 2, p. 1, http://www.rge.com/MediaLibrary/2/5/Content%20Management/Shared/SuppliersPartners/2015%20R

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settlement discussions, on June 15, 2016, the NYSPC filed an order in accord with a joint proposal in which the Commission approved a three-year electric rate plan for NYSEG and RG&E effective July 1, 2016 to April 30, 2019.[47] Under this rate plan the utilities' residential fixed charges will remain at current levels for the entirety of the rate plan.[48] This decision to maintain flat rates was based on the then pending REV order regarding the adoption of a ratemaking and utility revenue model policy framework.[49]

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ate%20Case/Revenue%20Allocation%20Rate%20Design%20Economic%20Development%20and%20Tariff%20Panel%20Exhibits%20-%20Final%205202015.pdf.

[47] New York Public Service Commission, *Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal*, Case 15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286, June 15, 2016, pp. 1-2, 45, https://www.nyseg.com/investplan/ratefiling2015.html.

[48] *Id.*, p. 21.

[49] New York Public Service Commission, *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*, Case No. 14-M-0101, May 19, 2016.

E. Eversource Energy [D]

Connecticut, Connecticut Public Utilities Regulatory Authority
Massachusetts, Massachusetts Department of Public Utilities
New Hampshire, New Hampshire Public Utilities Commission

Eversource provides service to customers in three different states as Connecticut Light & Power ("CL&P"), Public Service Company of New Hampshire ("PSNH"), and Western Massachusetts Electric Company ("WMECO"). WMECO's fixed residential charge seeks to recover the fixed costs of meters and services, meter reading, customer records and collection, customer service, and additional overhead expenses that may be allocated and included in customer-related costs. The fixed costs for PSNH and CL&P are the same as WEMCO, except that they additionally include minimum system cost components such as service transformers, lines, and poles.

Eversource uses embedded costs to estimate fixed cost and the utility's ECOSS are used for both class revenue allocation and rate design. Customer classes in the ECOSS are defined based on the rate classes of customers served. Eversource states that in some cases, rate classes are combined when identical service characteristics and rate alternatives exist. Additional studies are performed, including those of uncollectible costs, meter weights, and service transform rates, to develop cost allocation factors in order to align the cost of providing distribution service with the actual service provided to customers in each class. At CL&P, Eversource recently applied an EPMC in developing rates for street lighting service, but otherwise does not employ marginal costs in rate design or revenue allocation. The fixed charges in each of the states tend to recover less than the fixed costs determined by Eversource's cost of service analysis. Residential fixed customer charges tend to be less aligned with cost of service than fixed customer charges for commercial and industrial customers as more fixed cost recovery for residential customers occurs through energy charges.

Decoupling is used at both WMECO and CL&P on a total company level and is applied on a uniform per-kWh basis across all customer classes. PSNH does not use decoupling. The utility points out that this methodology may affect the extent to which fixed cost recovery can be accomplished through increases to the fixed monthly charge. Further, it notes that decoupling has been seen by some to place less emphasis on rate design. Eversource does have tiered and block rate structures in place in some of its companies; however, fixed charges are not exclusively used to reduce tier 1 rates in these cases.

At CL&P, the monthly fixed charge for the residential (non-heating) electric service class and residential TOU electric service class is $19.25/month.[50] The fixed charge is $23.75/month for the residential electric heating service class.[51] The Connecticut Public Utilities Regulatory Authority ("PURA") submitted a decision on December 17, 2014 requiring that CL&P submit a rate plan including an increase in the residential electric and residential electric heating fixed customer charges stated above. These were increased from $16.00/month and $20.25/month, respectively.[52] The PURA stated that it "generally prefers an approach that moves rates toward increased fixed cost recovery" and is "against lowering the customer charges from current levels, or eliminating the customer charges all together."[53]

As of March 2016, PSNH had a general residential fixed charge of $12.75/month and a residential TOD fixed charge of $29.61/month.[54] Eversource states that the fixed charges for PSNH has stayed at approximately the same level since 2010 and that there have been no recent rate cases addressing fixed charges in PSNH. WMECO has four residential classes split by heating and non-heating and also by residential classes that receive a low-income discount of 32 percent off their total bill.[55] The residential fixed charge for all of the classes is currently $6.00/month.[56] In 2011, WMECO proposed a fixed customer change increase from $8.53/month to $9.00/month for the

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[50] "Residential Electric Service," Connecticut Light and Power Company, DBA Eversource Energy, effective July 1, 2016, https://www.eversource.com/Content/docs/default-source/rates-tariffs/rate1.pdf?sfvrsn=10; "Residential Time-of-Day Electric Service," Connecticut Light and Power Company, DBA Eversource Energy, effective July 1, 2016, https://www.eversource.com/Content/docs/default-source/rates-tariffs/rate7.pdf?sfvrsn=10.

[51] "Residential Electric Heating Service," Connecticut Light and Power Company, DBA Eversource Energy effective, January 1, 2016, https://www.eversource.com/Content/docs/default-source/rates-tariffs/rate5.pdf?sfvrsn=10.

[52] Connecticut Public Utility Regulatory Authority, *Decision*, Docket No. 14-05-06, December 17, 2014, p. 190, http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/8ae5dacf2e5c72a685257dc6004b8034?OpenDocument&Highlight=0,13-01-19.

[53] *Id.*, pp. 187-188.

[54] "2016 Summary of Electric Rates," Eversource - NH, updated January 1, 2016, https://www.eversource.com/Content/docs/default-source/rates-tariffs/2015-nh-electric-rates.pdf?sfvrsn=2.

[55] "Residential – Low Income Schedule R-2," Western Massachusetts Electric Company, effective February 1, 2011, https://www.eversource.com/Content/docs/default-source/rates-tariffs/1034.pdf?sfvrsn=2.

[56] "Summary of Electric Delivery Service Rates," Western Massachusetts Electric Company, DBA Eversource Energy, effective February 1, 2016, https://www.eversource.com/Content/docs/default-source/rates-tariffs/1052.pdf?sfvrsn=20.

residential non-heating customer class and from $8.53/month to $9.50/month for the residential heating customer class.[57] The proposal was rejected by the Massachusetts Department of Public Utilities ("MDPU") due to its potential for adversely affecting bills for low-use low-income customers as "the rates for low-income customers [were] set at the same level as non-low-income customers as a result of [the] proceeding."[58] The MDPU directed WEMCO to file for a residential fixed customer charge of $6.00/month for both standard and low-income residential customers, resulting in the current value of the fixed charge.[59] There is currently no legal limit on the magnitudes of fixed charges for PSNH or WMECO, but legislation passed in Connecticut, effective July 1, 2015, calls for re-examination of the residential fixed charges in each electric distribution utility's next rate case.[60] The intent of the legislation is to limit fixed charges "to recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service."[61]

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57 Massachusetts Department of Public Utilities, *Final Order*, D.P.U 10-7, January 31, 2011, pp. 329- 330. https://www.eversource.com/Content/docs/default-source/Investors/wmeco-dpu-final.pdf?sfvrsn=0.

58 *Id.*, pp. 320, 331.

59 *Id.*, p. 331.

60 State of Connecticut General Assembly, *June Special Session, Public Act No. 15-5*, Senate Bill No. 1502, June 2015, pp. 149-150, https://www.cga.ct.gov/2015/act/pa/pdf/2015PA-00005-R00SB-01502SS1-PA.pdf.

61 *Id.*, p. 150.

F. United Illuminating Company D
Connecticut, Connecticut Public Utilities Regulatory Authority

United Illuminating ("UI") includes the fixed costs of metering, billing, customer care, service lines, transformers, and a portion of allocated poles and wires in their fixed charges. The portion of allocated poles and wires comes from UI's minimum system cost allocation approach, which classifies a portion of poles and wires as customer-related and the other portion as demand-related. The utility uses embedded costs to estimate fixed charges as Connecticut does not require a MCOSS. UI states that they regulate cost-based rates only for distribution as evidenced by the minimum system cost allocation approach. UI's ECOSS are used for both class revenue allocation and rate design. The classes for revenue allocation are those defined in the utility's tariffs. UI defines differences in cost of service for specific customer groups mostly by electric heat and non-heat customers. The utility's cost allocation to customer classes is derived from the NARUC Electric Utility Cost Allocation Manual, which suggests using direct assignment whenever possible, and then using the distribution cost of service study allocation.[62] According to the utility, PURA endorses a minimum system cost allocation method when classifying joint costs. A majority of UI's customer classes have fixed charges that recover nearly all of the costs of serving the customer; however, the residential customer class typically has a fixed charge that recovers less than the cost of service.

UI has decoupled its revenues from its sales of electricity. When defining annualized costs, UI includes carrying costs as part of the revenue requirement calculation that is based on a forward looking rate year. The rate base in this calculation is based on an average of beginning and ending period depreciated values. There is no difference in the application of carrying charges for fixed or demand costs. The utility has fixed charges for residential and non-residential customers. Historically, UI has applied fixed charges for two purposes: for equitable cost recovery among and within rate classes and for adequate recovery of allowed revenue requirements unrelated to volume or demand. UI indicates that with decoupling, the recovery of revenue requirements through the fixed charge is much less of a concern.

Over the last ten years, the utility's fixed charges have been moving closer to the level determined by the cost of service studies. The current residential fixed customer charge is

[62] National Association of Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, pp. 75, 83, 86-99.

$17.25/month for both standard and TOU residential customers.[63] There are no low-income discounts in Connecticut. In UI's last rate case, the utility submitted proposed tariffs for its two-year rate plan.[64] The utility states that there was no dramatic change in fixed charges and that fixed charges were simply updated using the PURA approved cost of service study. The utility also points out that, in general, PURA supports gradual rate movement toward the cost of service study results. PURA ordered that UI perform new cost of service studies for both years of the rate plan using specifications indicated by the authority in the August 2013 final decision.[65]

Connecticut legislation passed in 2015, as discussed above in the section regarding Eversource CL&P, limits the fixed charge to be no greater than the cost of serving the customer.[66] UI states that this will likely result in a residential customer charge that does not include the customer-allocated portion of poles and wires in the next rate case. On July 1, 2016, UI filed a rate request with PURA in which the utility proposed to maintain residential fixed charges at current levels.[67] The utility addressed the changes under the residential fixed charge legislation mentioned above stating that the proposed fixed charge "is *less* than the residential customer fixed charge that would be allowed under the statute" which UI calculated as $22.64/month in 2017 increasing to $25.42/month in 2019.[68]

[63] "Residential Rate R," United Illuminating Company, effective January 1, 2016, http://www.uinet.com/wps/wcm/connect/0cc7658041384518ac0fec7a239a91d1/821_Rate+Residential+Rate+R.pdf?MOD=AJPERES&CACHEID=0cc7658041384518ac0fec7a239a91d1; "Residential Time-of-Day Date RT," United Illuminating Company, effective January 1, 2016, http://www.uinet.com/wps/wcm/connect/19e4548041384518ac12ec7a239a91d1/822_Rate+Residential+RT.pdf?MOD=AJPERES&CACHEID=19e4548041384518ac12ec7a239a91d1.

[64] Connecticut Public Utility Regulatory Authority, *Decision*, Docket No. 13-01-19, August 14, 2013, http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/6b22a81f9e695f5685257bc800656220?OpenDocument&Highlight=0,13-01-19.

[65] *Id.*, pp. 153-154.

[66] State of Connecticut General Assembly, *June Special Session, Public Act No. 15-5*, Senate Bill No. 1502, June 30, 2015, pp. 149-150, https://www.cga.ct.gov/2015/act/pa/pdf/2015PA-00005-R00SB-01502SS1-PA.pdf.

[67] Connecticut Public Utility Regulatory Authority, *Brief of the United Illuminating Company*, Docket No. 16-06-04, October 17, 2016, p. 133.

[68] *Id.*, pp. 132-133.

II. MIDWEST AND SOUTH

A. Commonwealth Edison

Illinois, Illinois Commerce Commission

Commonwealth Edison ("ComEd") aggregates total fixed costs into customer-related services, metering services, and distribution costs.[69] ComEd's costs applying to the fixed charge include services, customer installations, billing, indirect uncollectibles, customer information, and revenue-related customer costs. The utility uses embedded costs to estimate fixed costs through an ECOSS. The ECOSS is also used to develop ComEd's rate design.[70] The utility has fixed charges for both residential and non-residential customers.[71] Regarding the issue of joint costs, ComEd includes the Illinois Electricity Distribution Tax under distribution costs, which is fixed, although the tax varies with kWh. Due in part to the utility's last rate case, discussed below, ComEd's fixed charge application and methodology are consistent with the practice of limiting fixed charges to customer-related costs. However, ComEd's position is that in addition to customer-related costs, distribution facilities costs are fixed costs that should also be recovered through a fixed charge.

There are four residential service classes including single- and multi-family with and without space heat.[72] The residential customer charges range from $7.00/month for multi-family without electric space heat to $11.31/month for single-family with electric space heat[73] plus an added Incremental Distribution Uncollectible Cost Factors ("IDUF")[74] cost which is approximately

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[69] Illinois Commerce Commission, *Exhibit 7.01 - Embedded Cost of Service Study Pro Forma Test-Year Ended December 2014*, Docket No. 15-0287, April 15, 2015, pp. 76-79, https://www.icc.illinois.gov/docket/files.aspx?no=15-0287&docId=228074.

[70] Illinois Commerce Commission, *Exhibit 7.03 - Commonwealth Edison Company Update Rate Design*, Docket No. 15-0287, April 15, 2015, https://www.icc.illinois.gov/docket/files.aspx?no=15-0287&docId=228074.

[71] *Ibid.*

[72] *Ibid.*

[73] "Electricity Delivery Service Charges - Supplement to Rate DSPP," Commonwealth Edison Company, effective December 14, 2015, Sheet No. 24, https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf.

[74] The IDUF is calculated as described in the Ride UF - Uncollectible Factors schedule. "Electricity Rider UF – Uncollectible Factors," Schedule of Rates for Electric Service, Commonwealth Edison Company effective February 27, 2012, Sheet No. 267.4,

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$1.01 for all residential customer classes effective September 2016 through May 2017.[75] There is also an additional standard metering service charge which is $4.33/month plus IDUF for all residential customers.[76] The utility does not offer income-based discounts. As of April 2015, ComEd's fixed charges recover 40 percent of ComEd's fixed costs.[77]

ComEd conducts a Rate Design Investigation every three years. In ComEd's 2010 general rate case, the Illinois Commerce Commission ("ICC") approved a modified residential rate design that would result in a 50 percent recovery of fixed costs through fixed charges.[78] The ICC stated in their final order that "the Commission has recognized the importance of recovering fixed costs predominantly through fixed charges and the Commission finds that one of the most important steps in bringing ComEd's rate design in line with its costs is to properly align costs ComEd incurs to provide delivery service."[79] The Commission goes on to state that rate designs should reflect cost causation. While there is no limitation on ComEd's residential fixed charges, they must be approved by the Illinois Commerce Commission ("ICC") and the utility must submit an annual filing which includes a reconciliation of the revenue requirement for the prior year.

In ComEd's most recent rate case, the ICC issued a decision on December 13, 2013, approving ComEd's rate design proposal for the multi-family/heating fixed customer charge but rejected the

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https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf.

75 "Electricity Incremental Uncollectible Cost Factors – Supplement to Rider UF(1)," Commonwealth Edison Company, effective December 14, 2015, Sheet No. 20, https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/53_Incremental_Uncollectibles.pdf.

76 "Electricity Delivery Service Charges - Supplement to Rate DSPP," Commonwealth Edison Company, effective December 14, 2015, Sheet No. 24, https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf.

77 Commonwealth Edison uses the ECOSS to develop rates. Illinois Commerce Commission, *Exhibit 7.03 - Commonwealth Edison Company Update Rate Design*, Docket No. 15-0287, April 15, 2015, https://www.icc.illinois.gov/docket/files.aspx?no=15-0287&docId=228074. See also Commonwealth Edison uses the ECOSS to develop rates. *Ibid*, see also Illinois Commerce Commission, *Exhibit 7.00 – Direct Testimony of John L. Leick*, Docket No. 15-0287, April 15, 2015, https://www.icc.illinois.gov/docket/files.aspx?no=15-0287&docId=228074.

78 Illinois Commerce Commission, *Order*, Docket No. 10-0467, May 24, 2011, p. 232, https://www.icc.illinois.gov/docket/files.aspx?no=10-0467&docId=166950.

79 *Ibid.*

utility's other residential fixed customer charge proposals.[80] Instead, the Commission ordered a decrease in the fixed customer charge for single family residential classes and an increase in the fixed customer charge for the multi-family, no-heating class as proposed by the Attorney State General of Illinois ("AG"). This decision effectively reversed the 50 percent fixed charge recovery rate, as the Commission pointed out that ComEd's previously approved rate design resulted in "charges substantially in excess of the cost of service for low-use customers in two residential classes."[81] Additionally, the Commission approved a change in the allocation of combination poles to be 100 percent primary service, excluding them from consideration as customer-related fixed costs.[82] Proponents of this decision explained that the combination poles are primarily meant to accommodate primary lines and that "attachment of secondary lines is a convenience for secondary service."[83]

[80] Illinois Commerce Commission, *Order*, Docket No. 13-0387, December 18, 2013, p. 75, https://www.icc.illinois.gov/docket/files.aspx?no=13-0387&docId=207265.

[81] *Id.*, p. 74.

[82] *Id.*, p. 25.

[83] *Ibid.*

B. DTE Energy
Michigan, Michigan Public Service Commission

DTE Energy's ("DTE") fixed costs, as defined by the Michigan Public Service Commission ("MPSC"), include metering, overhead and underground services, customer records and collection, and customer service expenses.[84] While the MPSC determines the limitations of the customer-related fixed costs using marginal cost methodology, DTE uses embedded costs to estimate the MPSC-defined fixed costs. The utility uses ECOSS in the development of rate design and for allocation of revenue. The overall customer class costs match the ECOSS; however, the customer, demand, and energy components may not exactly match that of the study. DTE indicates that rates are designed to recover the power supply and distribution deficiencies assigned to each respective class by the cost of service study. DTE defines customer classes as distribution customer classes and power supply classes. Distribution customer classes are determined by voltage level, where secondary voltage is split into residential and commercial, and street lighting is considered separate due to the unique characteristics of the class. The power supply classes include residential, residential space heating, general service, secondary schools, large general service, primary, primary schools, interruptible supply, metal melting and process heat, and lighting. Costs are allocated by measuring the demands at each voltage level and allocating the costs associated with that portion of the system to the class using it.

Fixed customer charges and rate structures vary across the different customer classes, but do not vary by residential rate schedule. A majority of the residential rates are in the same power supply class in the ECOSS with the exception of the residential whole-house space heating class. For the distribution class, which dictates the monthly fixed charge, all residential rates are in the same cost of service class. All residential customers with the same voltage have the same fixed customer charge. While the most common residential class has a tiered structure, the fixed charge does not depend on whether or not the class has a tiered structure. DTE follows the practice of limiting fixed costs to customer-related costs when deriving the fixed customer charge.

When defining annualized costs, DTE performs a revenue requirement calculation of customer-related costs that serves as the basis for the utility's customer charge. DTE states that the carrying

[84] Further details on the stance of the MPSC on fixed costs used to estimate fixed charges is referred to in DTE's rate case information later on in this section.

costs associated with the fixed costs elements within the rate base are calculated by multiplying the rate base by the pre-tax weighted average cost of capital.[85]

Currently, all residential customers pay a fixed service charge of $6.00/month.[86] The $6.00/month fixed charge was originally recommended by the MPSC Staff in DTE Energy's 2008 rate case, who stated that "certain costs do not vary with the amount of energy a customer uses and the company should be able to collect a portion of these fixed costs."[87] DTE offers low-income discounts delivered through monthly bill credits. The current residential fixed charge covers less than 25 percent of customer-related costs.

In the utility's most recent rate case, DTE proposed increasing customer fixed charges gradually from $6.00/month to $10.00/month using the minimum distribution method,[88] which is described in the NARUC Electric Utility Cost Allocation Manual.[89] On December 11, 2015, the MPSC rejected this proposal. Although agreeing that the costs included in DTE's cost of service study were customer-related, the MPSC argued that some of these costs do not "vary with the number of customers on the system."[90] The MPSC determined that the customer charge should reflect the marginal cost of connecting a customer to the system, which excludes some costs associated with the minimum distribution system.[91]

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[85] The rate base is the net plant plus construction work in progress ("CWIP"). Other elements included in the revenue requirement are Depreciation Expense, Property Taxes, Operating and Maintenance Expenses, General and Intangible Plant, Employee Pensions and Benefits, Administrative and General Expense, and Employment Taxes.

[86] "Electric Rate Book," DTE Energy, effective March 1, 2016, Sheet No. D-1.00-17.00, http://www.dleg.state.mi.us/mpsc/electric/ratebooks/dtee/dtee1curd1throughend.pdf.

[87] Michigan Public Service Commission, *Opinion and Order*, Case No. U-15244, December 23, 2008, p. 92, http://efile.mpsc.state.mi.us/efile/docs/15244/0567.pdf.

[88] Michigan Public Service Commission, *Order*, Case No. U-17767, December 11, 2015, p. 116, http://efile.mpsc.state.mi.us/efile/docs/17767/0485.pdf.

[89] National Association of Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, pp. 138-142.

[90] Michigan Public Service Commission, *Order*, Case No. U-17767, December 11, 2015, p. 119, http://efile.mpsc.state.mi.us/efile/docs/17767/0485.pdf.

[91] *Ibid.*

C. Indiana Michigan Power Company

Indiana, Indiana Utility Regulatory Commission
Michigan, Michigan Public Service Commission

Fixed costs that Indiana Michigan Power Company ("I&M") collects through the residential fixed charge include distribution costs such as metering costs, customer account and service expenses, general and administrative expenses, depreciation, and taxes. Historically and currently, the utility's fixed charges are designed to collect customer-related fixed costs. Demand-related fixed costs such as production and transmission plant costs and costs of distribution poles and lines are not included in I&M's residential fixed charge. The MPSC mandates that distribution pertaining exclusively to a given customer be classified as customer-related while other distribution costs be classified as demand-related.[92] The Indiana Utility Regulatory Commission ("IURC") does not provide specific customer-related fixed cost definitions. The utility has fixed charges for nearly all of its customer classes.[93]

I&M uses embedded costs for ECOSS conducted in both states. These studies are used for both revenue allocation and rate design. I&M indicates that the first step in the utility's residential service rate design is to determine the full cost of service for the class then to propose a charge which covers the full cost, if reasonable. The ECOSS are conducted using a standard Functionalize, Classify and Allocate/Assign methodology to allocate costs to customer classes. Classes used for revenue allocation are the same as defined in the utility's tariff classes. To address joint costs, I&M uses ECOSS to allocate and assign costs as either demand- or energy-related cost where most demand-related costs are considered fixed costs. I&M occasionally determines annualized costs for meters or lighting fixtures for rate design purposes. The utility calculates annual investment carrying charges for various investment lives in years and uses the appropriate factor for the expected life of the investment.

I&M Indiana's current standard residential service charge is $7.30/month.[94] This collects 100 percent of Indiana's customer-related fixed costs. The utility also has a residential TOU rate

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[92] I&M's demand-related fixed costs are often collected from non-residential customers through demand charges. I&M's residential customer two-part rates do not include a demand charge. Michigan Public Service Commission, *Opinion and Order Amending Standard Rate Application Filing Forms and Instructions*, Case No. U-4471, May 10, 1976, Attachment A, p. 2.

[93] I&M's Irrigation Service and Fort Wayne Streetlighting – Customer Owned and Maintained System customer classes do not have a monthly fixed charge.

[94] "Tariff R.S. (Residential Electric Service)," Schedule of Tariffs and Terms and Conditions of Service Governing the Sale of Electricity in the State of Indiana, Indiana Michigan Power Company, effective

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schedule which has a fixed charge of $8.50/month.[95] In I&M Indiana's last rate case, decided February 13, 2013, the IURC approved I&M Indiana's ECOSS.[96] The IURC indicated that the results from the studies should be used in customer class revenue allocation and in the utility's electric retail rate design.[97]

I&M Michigan's current standard residential fixed charge is $7.25/month.[98] This collects slightly above the full residential customer-related fixed costs. The utility also has a residential TOU rate, which includes a fixed charge of $8.45/month.[99] I&M Michigan's last rate case ended in a settlement agreement approved by the MPSC on August 14, 2015.[100] The settlement authorized revised rates for I&M Michigan on the basis of the use of the utility's revenue requirement which was adopted and approved in a prior case.[101] I&M Michigan's original proposal included increasing the general residential fixed charge to $9.10/month and the residential TOU fixed charge to $10.30/month;[102] however, the residential fixed charge increases were not present in the final rates agreed upon in the settlement.[103]

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February 28, 2013, Sheet No. 4, https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_16_09-28-2016.pdf.

95 *Id.*, "Tariff R.S. – TOD (Residential Time-of-Day Service)," Sheet No. 6.

96 Indiana Utility Regulatory Commission, *Order of the Commission*, Cause No. 44075, February 13, 2013, pp. 115-116.

97 *Ibid.*

98 "Tariff RS (Residential Electric Schedule)," Schedule of Tariffs Governing the Sale of Electricity, Indiana Michigan Power Company, effective December 2010, Sheet No. D-2.00, https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Michigan/IM_MI_TB_09-28-2016.pdf.

99 *Id.*, "Tariff RS-TOD (Residential Time-of-Day Service)," Sheet No. D-6.00.

100 Michigan Public Service Commission, *Order Approving Settlement Agreement*, Case No. U-17698, August 14, 2015, http://efile.mpsc.state.mi.us/efile/docs/17698/0043.pdf.

101 *Id.*, p. 2.

102 Michigan Public Service Commission, *Pre-Filed Direct Testimony of Matthew W. Nollenberger*, Case No. U-17698, December 15, 2014, Exhibit IM-4 (MWN-4), pp. 2-3, http://efile.mpsc.state.mi.us/efile/docs/17698/0010.pdf.

103 Michigan Public Service Commission, *Order Approving Settlement Agreement*, Case No. U-17698, August 14, 2015, p. 2, http://efile.mpsc.state.mi.us/efile/docs/17698/0043.pdf.

D. Madison Gas & Electric
Wisconsin, Wisconsin Public Service Commission

Madison Gas and Electric's ("MGE") fixed charge is called the Grid Connection and Customer Service Charge. The Customer Service portion of the charge includes the costs of customer accounts and services, and a portion of allocated administrative and general expenses, general and common plant depreciation and return, and taxes. The Grid Connection portion includes distribution plant depreciation and return, operating and maintenance expenses, and an allocated portion of general and common plant depreciation and return, and taxes. MGE bases the distribution cost component of its fixed costs on the minimum distribution system, which does not vary by customer and is the minimum distribution capacity necessary for all customers to be connected to the grid. In addition to the minimum distribution system, other joint costs allocated to the fixed charge include an allocated portion of administrative and general expenses, general and common plant depreciation and return, and taxes.[104] Costs associated with generation and transmission capacity, as well as the costs for the distribution capacity above the minimum distribution system, are considered demand-related. Thus, they are not included in the fixed charge cost allocation.[105]

MGE uses embedded costs to develop the unbundled cost of service components. Customer classes are determined by the rate schedule in the ECOSS used in the utility's last rate case. MGE does not directly use annualized carrying costs in its ECOSS. Instead, MGE explains that it starts with the utility's full forecast test year revenue requirement, which directly includes depreciation, associated operating and maintenance expenses, and allocated taxes. In allocating revenue, the utility has used customer classes defined by MGE's rate schedules in its last ECOSS. In this methodology, general residential service customers would be separate from residential TOU service customers in allocating revenue in the ECOSS. MGE indicates that this methodology has posed some challenges, particularly in the non-residential classes. Consequently, the utility is evaluating whether it should employ broader customer classes in its future ECOSS. All customer class schedules include a fixed charge. Although the most recently approved fixed charges in MGE's last filing were based off of one cost of service study, MGE indicates that they proposed a variety of cost of service studies and additional studies to reflect

[104] Labor allocators are in many cases used to allocate the above costs. Customer accounts and customer service FERC accounts are primarily labor expenses.

[105] However, from an accounting perspective, costs associated with generation and transmission capacity are fixed year-to-year.

the positions of various stakeholders.[106] All of these cost of service studies, as well as those submitted by the PSCW Staff, are considered by the PSCW in rate decisions in Wisconsin.[107]

MGE's current residential Customer Service and Grid Connection Charge is approximately $19.00/month,[108] an increase from the previous level of $10.44/month.[109] The utility has a general residential rate schedule as well as a residential TOU rate schedule, both of which have the same Customer Service and Grid Connection Charge.[110] In 2016, the utility expects to collect 21 percent of fixed costs allocated to residential customers through residential fixed charges compared to the 23 percent estimated in the utility's fully unbundled embedded cost of service study. In MGE's 2015 rate case, the utility had originally proposed two separate fixed charges in which the Customer Charge would recover customer-related costs and the Grid Connection Charge would recover distribution costs associated with serving the customer.[111] The charges remained separate until the final decision, in which the PSCW stated that two charges may be "confusing for customers" and combined the two charges into a single fixed charge.[112] The Commission approved increasing the Customer Service charge component of the residential fixed charge to $14.97/month and the Grid Connection charge portion to $4.03/month.[113] MGE states that they had originally proposed a residential Grid Connection charge of $7.00/month and that the rejection of the Grid Connection component increase has prevented the utility from recovering the costs from the minimum distribution system. The utility's cost of service study from the rate case indicated that the residential allocation of fixed costs is approximately $21.55/month, indicating that the $19.00/month combined Customer Service and Grid Connection Charge recovers approximately 88 percent of residential fixed costs.[114]

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[106] Public Service Commission of Wisconsin, *Final Decision*, Docket No. 3270-UR-102, December 23, 2014, pp. 30-33, http://psc.wi.gov/apps35/ERF_search/content/SearchRef.aspx?docid=226563.

[107] *Id.*, p. 7.

[108] "Residential Service Schedule Rg-1," Madison Gas and Electric Company, effective January 1, 2015, https://www.mge.com/images/PDF/Electric/Rates/E06.pdf.

[109] Public Service Commission of Wisconsin, *Final Decision*, Docket No. 3270-UR-102, December 23, 2014, p. 2, https://psc.wi.gov/apps35/ERF_search/content/SearchRef.aspx?docid=226563.

[110] "Residential Electric Rates," Madison Gas and Electric, accessed October 23, 2016, https://www.mge.com/customer-service/home/elec-rates-res/.

[111] Public Service Commission of Wisconsin, *Final Decision*, Docket No. 3270-UR-102, December 23, 2014, p. 35-49, https://psc.wi.gov/apps35/ERF_search/content/SearchRef.aspx?docid=226563.

[112] *Id.*, p. 49.

[113] *Id.*, p. 35, 48.

[114] *Id.,* p. 32.

Despite the rejection, the Commission stated that "fixed charges should be increased to more closely reflect the utility's fixed costs to provide basic service to a customer."[115] MGE has used fixed charges for over 34 years and applies fixed charges to appropriately charge customers for the fixed costs of providing service. This is consistent with the practice of achieving fixed cost recovery through fixed charges. The utility does not seek to increase the residential fixed charge in its 2017 rate case filed in April 2016 in efforts "ensure that all customers benefit from changing technology" under the utility's Energy 2030 Framework.[116]

[115] *Id.*, p. 48.

[116] "MGE Files Rate Changes for 2017," MGE news release, April 8, 2016, https://www.mge.com/newsroom/news/Compnews/20160408.htm. See also "MGE's Energy 2030 Framework," MGE, https://www.mge.com/community-conversations/framework.htm.

E. Oklahoma Gas & Electric
Oklahoma, Oklahoma Corporation Commission

Oklahoma Gas and Electric's ("OG&E") fixed charge includes recovery of fixed costs related to customer billing, administration, metering, service drop, and a portion of the transformer, lines and poles. OG&E uses a fully allocated ECOSS to estimate fixed costs for fixed charge recovery and uses the same ECOSS for class revenue allocation and rate design. OG&E's ECOSS customer classes are defined by type of customer (e.g., residential, municipal, etc.) and usage characteristics such as annual maximum kW demand and load factor. OG&E bases its allocation methodology and ECOSS on the NARUC Electric Utility Cost Allocation Manual. Specifically, the utility relies on the zero-intercept method to identify the customer-related and demand-related components for certain distribution system costs.[117] Other costs are allocated to customer groups based upon demand or customer count. Regarding the recovery of the estimated fixed costs, while the utility collects nearly all of the fixed costs associated with non-residential customers through a fixed charge, OG&E has tended to collect less than the full fixed costs for residential customers through fixed charges.

The current fixed customer charge for general residential service and residential TOU service customers is $13.00/month.[118] OG&E has a block energy rate structure in some of the customer class tariffs, but does not use fixed charges to reduce the initial block prices. Instead, the utility uses the initial block prices to recover any additional fixed charges not covered by the customer charge. OG&E offers a $10/month credit applied to the customer's bill to low-income residential customers deemed qualified by the Oklahoma Department of Human Services.[119] The credit is

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[117] National Association of Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, pp. 92-95.

[118] "Standard Pricing Schedule: R-1 Residential Service," Oklahoma Gas and Electric Company, effective August 2, 2012, Sheet No. 3.00, https://oge.com/wps/wcm/connect/de21b39f-2d52-402f-82e6-a6826999d724/3.00+R-1.pdf?MOD=AJPERES&CACHEID=de21b39f-2d52-402f-82e6-a6826999d724; "Standard Pricing Schedule: R-TOU Residential Time-of-Use," Oklahoma Gas and Electric Company, effective August 2, 2012, Sheet No. 3.30, https://oge.com/wps/wcm/connect/fe4b2135-3d11-4f9d-ba8d-109ab630d09b/3.30+R-TOU.pdf?MOD=AJPERES&CACHEID=fe4b2135-3d11-4f9d-ba8d-109ab630d09b.

[119] "Standard Pricing Schedule: LIAP Low Income Assistance Program Rider," Oklahoma Gas and Electric Company," effective August 2, 2012, Sheet No. 50.10, https://oge.com/wps/wcm/connect/fae1d65e-cf37-49c9-851b-0d8e684fde24/50.10+LIAP.pdf?MOD=AJPERES&CACHEID=fae1d65e-cf37-49c9-851b-0d8e684fde24.

funded by other retail customers. OG&E's recovery of fixed costs through fixed charges has ranged from 50 percent to 100 percent, varying by customer class and service level.

In its current rate case before the Oklahoma Corporation Commission ("OCC") filed in December 2015,[120] OG&E is proposing to increase the fixed charge to $26.50/month.[121] This proposed fixed charge includes some transmission and distribution costs. OG&E indicates that the utility is proposing to collect all of the fixed costs per customer class through a fixed customer charge. As a result, the utility has also proposed eliminating the block energy structure and moving related costs into the customer and energy charges. The utility is currently awaiting a decision by the OCC.

[120] Oklahoma Corporation Commission, *Application Package Volume 1*, Cause No. PUD 201500273, December 18, 2015, http://imaging.occeweb.com/AP/CaseFiles/occ5248940.pdf.

[121] Oklahoma Corporation Commission, *Supplemental Package Volume III*, Cause No. PUD 201500273, December 18, 2015, Sheet No. 3.00, p. 6, http://imaging.occeweb.com/AP/CaseFiles/occ5249126.pdf.

F. Omaha Public Power District

Nebraska, Omaha Public Power District Board of Directors

The Omaha Public Power District ("OPPD") bases its fixed costs on embedded costs. OPPD's cost of service studies are used for both revenue allocation and rate design. The utility uses a standard cost of service methodology to address joint costs. When defining annualized costs, the utility employs a single-asset life cycle for fixed assets. The exception to this is street lighting, for which OPPD uses a single-asset life with replacement. OPPD does not abide by the practice of limiting fixed charges to the recovery of customer-related costs, as its fixed costs for recovery through fixed charges include distribution system fixed costs.

OPPD has four different classifications of residential customers, including general, conservation, employee, and multi-family of which the general and conservation are the most common. OPPD's fixed charge for the general residential and residential conservation rate schedules is $15.00/month.[122] This rate was increased from $10.25/month as of June 1, 2016 and going forward, will increase in annual increments of $5.00/month per year to $30.00/month by 2019, as approved by the OPPD Board of Directors on December 17, 2015.[123] The approved increase was roughly $5.00 less than what was originally proposed by OPPD.[124] The rate plan, according to the Board, is intended to "strike a better balance between fixed and variable costs."[125] This updated charge currently covers all customer costs and aims to maintain the coverage of costs through 2019. The costs covered by this fixed charge include customer and distribution system fixed costs directly assigned to customers. Along with the fixed charge increase, the OPPD Board approved a decrease in the energy charge and announced the addition of a new Residential Low Usage/Low Income Customer Program, implemented in June 2016,[126] which applies a bill credit to the

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[122] "Residential Rates," OPPD, accessed October 23, 2016, http://www.oppd.com/residential/residential-rates/. See also "Residential Rates," OPPD, effective June 1, 2016, http://www.oppd.com/media/207840/oppd-rate-manual.pdf#nameddest=110.

[123] "OPPD Board Approves Rate Restructuring Plan & 2016 Budget," OPPD news release, December 17, 2015, http://www.oppd.com/news-resources/news-releases/2015/december/oppd-board-approves-rate-restructuring-plan-2016-budget/.

[124] *Ibid.*

[125] *Ibid.*

[126] *Ibid.*

customer's monthly bill.[127] Notably, OPPD also has a minimum monthly bill for residential customers of $17.07/month.[128]

[127] "OPPD Develops Program to Help Low Usage/Low Income Customers," OPPD news release, December 15, 2015, accessed October 24, 2016, http://www.oppd.com/news-resources/news-releases/2015/december/oppd-develops-program-to-help-low-usagelow-income-customers/.

[128] "Residential Rates," OPPD, effective June 1, 2016, http://www.oppd.com/media/207840/oppd-rate-manual.pdf#nameddest=110.

G. Westar Energy
Kansas, Kansas Corporation Commission

Westar's fixed costs classified as customer service include meters, billing, meter reading, service lines, and a portion of distribution.[129] The utility relies on embedded costs to estimate their fixed costs.[130] Westar's ECOSS are used for both the allocation of revenue as well as rate design.[131] Westar uses FERC depreciation rates authorized by the state, reported in FERC Form 1, for their retail rates and ECOSS.[132] In order to allocate joint costs and common costs, Westar uses principles of cost causation. The utility uses plant and payroll as allocation factors for costs that are not able to be allocated by external allocation factors such as customer, demand, or energy. The utility's rate classes have been based on class of service (residential, commercial, industrial, etc.), end-use classification (residential regular, residential all-electric), quality of service (firm or interruptible), and type of service (full requirements, partial requirements).[133] The utility has fixed charges for non-residential customers as well as residential customers.

Currently, Westar has a standard residential service fixed customer charge of $14.50/month.[134] The utility does not offer income-based discounts, as the state has ruled them to be discriminatory. In Westar's 2015 rate case, the utility proposed to increase the monthly fixed charge for residential customers on a phased-in basis of $3.00/month per year for the following four years.[135] The rate case ended in a stipulation and agreement on September 24, 2015[136] in

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[129] Kansas Corporation Commission, *Direct Testimony of H. Edwin Overcast – Westar Energy*, Docket No. 15-WSEE-115-RTS, March 2, 2015, pp. 12, 16-17, http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302135218.pdf?Id=951fb4b5-bea0-4462-baee-e41294e8ed18.

[130] *Id.*, Appendix B.

[131] *Id.*, pp. 5-6, Appendix B.

[132] Information obtained through a follow-up phone call with Westar representatives.

[133] Kansas Corporation Commission, *Direct Testimony of H. Edwin Overcast – Westar Energy*, Docket No. 15-WSEE-115-RTS, March 2, 2015, p. 11, http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302135218.pdf?Id=951fb4b5-bea0-4462-baee-e41294e8ed18.

[134] "Residential Standard Service," Westar Energy, effective October 28, 2015, https://www.westarenergy.com/Portals/0/Resources/Documents/Tariffs/Residential_Service_1015.pdf.

[135] Kansas Corporation Commission, *Direct Testimony of Cindy S. Wilson – Westar Energy,* Docket No. 15-WSEE-115-RTS, March 2, 2015, pp. 9-10, http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302134521.pdf?Id=dac36651-3bfb-40bc-a220-1f75add1070d.

which the Kansas Corporation Commission ("KCC") approved an increase in the residential fixed charge from $12.00/month to $14.50/month which was proposed in a joint motion.[137] Before the fixed charge increase, 73 percent of Westar's cost-based residential revenue requirements were fixed and only 11.5 percent of these residential fixed costs were recovered through fixed charges.[138] While historically Westar's customer charge has been limited to the collection of customer-related costs, in the latest rate case, the utility attempted to increase fixed charges to recover costs beyond the customer-related cost in the fixed charge. The approved fixed charge of $14.50/month does not cover costs beyond customer-related costs; however, the fixed charge was renamed "Basic Service Fee" in anticipation of further costs being covered by the fixed charge in the future. [139]

Continued from previous page

136 Kansas Corporation Commission, *Order Approving Stipulation and Agreement*, Docket No. 15-WSEE-115-RTS, September 24, 2015, http://estar.kcc.ks.gov/estar/ViewFile.aspx/20150924104744.pdf?Id=29b7b55e-b40c-4f66-9335-153bfe44a81e.

137 Kansas Corporation Commission, *Joint Motion to Approve Stipulation and Agreement*, Docket No. 15-WSEE-115-RTS, August 6, 2015, p. 9, Appendix B, http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150806151046.pdf?Id=06892f1c-caa8-491c-88f3-ea58aba56f61. See p. 47 of Order in footnote 128 for approval of rates and schedules from the above filing.

138 Transmission costs were not included in the calculations to arrive at these percentages. Kansas Corporation Commission, *Direct Testimony of H. Edwin Overcast – Westar Energy*, Docket No. 15-WSEE-115-RTS, March 2, 2015, pp. 5-6, 13, http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302135218.pdf?Id=951fb4b5-bea0-4462-baee-e41294e8ed18.

139 Westar states in its response that customer charges should be based on customer allocation of distribution costs using direct assignment where possible and the minimum system concept to classify costs that have both a demand and customer component. This is explained in Dr. Overcast's testimonies in Westar's most recent rate case. Kansas Corporation Commission, *Direct Testimony of H. Edwin Overcast – Westar Energy*, Docket No. 15-WSEE-115-RTS, March 2, 2015, pp. 22-23, http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302135218.pdf?Id=951fb4b5-bea0-4462-baee-e41294e8ed18.

H. Florida Power & Light

Florida, Florida Public Service Commission

Fixed costs used to estimate Florida Power and Light's ("FPL") fixed charges include customer-related charges such as pull-offs, installations on customer premises, meters, service drops, and customer collections, services, and sales costs. FPL uses embedded costs to estimate fixed costs, as required by the Florida Public Service Commission ("FPSC").[140] The utility uses its ECOSS for rate design, but also relies on factors such as bill impacts and gradualism, in the determination of appropriate rate levels. Classes in the ECOSS are based on FPL's rate schedules, and costs are assigned to the classes based on cost causation. Optional rate schedules are combined with standard schedules in the ECOSS. FPL allocates joint costs based on labor ratios or plant balances. In defining annualized costs, FPL uses a forecast year to assess carrying costs. It does not make pro-forma adjustments to annualize costs.

The utility has a two-tier rate structure, with the first tier applying to the first 1,000 kWh of use and the second tier applying to use greater than 1,000 kWh; however, the fixed customer charge is not intended to reduce tier 1 rates. FPL indicates that the rate design is based on maintaining a one cent spread between the two rate tiers, regardless of the amount of revenue recovered through the fixed customer charge. FPL's application and methodology of limiting fixed costs included in the fixed charge to customer-related costs has not changed over time. FPL has fixed charges for residential, commercial, and industrial customers.

There are two rate schedules for residential customers: the residential service schedule and the TOU residential rider rate schedule. Residential service customers pay a fixed charge of $7.87/month and customers on the residential TOU rider schedule pay $12.36/month.[141] FPL indicates that the higher TOU fixed charge is meant to cover the incremental cost of the TOU meter. Residential customers pay a portion of fixed costs through the fixed charge with the fixed charge recovering approximately 26 percent of FPL's residential fixed costs. FPL's last major rate

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[140] Florida Public Service Commission, *In re: Consideration of PURPA Standards in the following dockets: Peak Load Pricing Declining Block Rates Cost of Service Load Management Decision Making*, Dockets Nos. 780793-EU, 790571-EU, 790593-EU, 790594-EU, 790859-EU, Order No. 10179, August 3, 1981, p. 9.

[141] "Residential Rates, Clauses and Storm Factors," FPL, effective September 2016, https://www.fpl.com/rates/pdf/Sept2016-Residential.pdf.

case reached settlement in January 2013, approving FPL's proposed fixed charge increase.[142] The residential service fixed charge increased from $5.90/month to $7.00/month and the residential TOU rider fixed charge was set at $11.00/month to replace the original residential TOU schedule.[143] The rate increase was approved in anticipation of FPL's three new energy centers.[144] In FPL's 2009 rate case, the FPSC approved an increase in residential fixed charges from $5.69/month to $5.90/month.[145] The FPSC stated that they agreed with FPL's proposed methodology, which excluded the minimum distribution system in the estimation of fixed charges.[146]

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142 Florida Public Service Commission, *Order Approving Revised Stipulation and Settlement*, Docket No. 120015-EI, Order No. PSC-13-0023-S-EI, January 14, 2013, http://www.psc.state.fl.us/library/filings/13/00264-13/00264-13.pdf.

143 *Id.*, Exhibit B, pp. 31-32. See also Florida Public Service Commission, *Testimony & Exhibits of: Renae B. Deaton*, Docket No. 120015-EI, Summary of Proposed Rates Exhibit RBD-7, p. 1, http://www.psc.state.fl.us/library/filings/12/01609-12/01609-12.pdf.

144 These new energy centers included the Cape Canaveral Clean Energy Center in June 2013, the Riviera Beach Energy Center in June 2014, and the Port Everglades Energy Center in April 2016. Florida Public Service Commission, *Order Approving Revised Stipulation and Settlement*, Docket No. 120015-EI, Order No. PSC-13-0023-S-EI, January 14, 2013, pp. 5-6, http://www.psc.state.fl.us/library/filings/13/00264-13/00264-13.pdf.

145 Florida Public Service Commission, *Order Denying in Part, and Granting in Part, Florida Power & Light Company's Request for a Permanent Rate Increase and Setting Depreciation and Dismantlement Rates and Schedules*, Docket No. 080677-EI, Order No. PSC-10-0153-FOF-EI, March 17, 2010, p. 214, http://www.psc.state.fl.us/library/filings/10/01885-10/01885-10.pdf.

146 *Id.*, p. 175.

I. Georgia Power
Georgia, Georgia Public Service Commission

In calculating customer-related fixed costs, Georgia Power includes costs of metering and billing in addition to cost components of the distribution system using minimum distribution methodology. The minimum distribution system includes poles, overhead conductors, underground conduits, conductors and devices, and line transformers. The utility uses embedded costs to estimate fixed costs and the same ECOSS are used for rate design and revenue allocation. Georgia Power has eight customer rate groups, including one residential class. Costs are allocated to these classes based on function and voltage level of service. Costs are further allocated using number of customers and phases of metering among other factors. While Georgia Power does have a tiered residential rate structure, the fixed charge is not used to reduce tier 1 rates.

The current residential fixed customer charge is $10.00/month plus applicable recovery tariffs.[147] Georgia Power also offers a low-income senior citizen discount which reduces the customer's utility bill by $24.00/month, including $18.00/month for metered service[148] and $6.00/month for fuel.[149] Georgia Power's fixed charges recover approximately half of the fixed costs. Georgia Power's last major rate case ended with a settlement agreement order by the Georgia Public Service Commission ("GPSC") on December 23, 2013.[150] Georgia Power has updated its tariffs annually, with the approval of the GPSC, based on stipulations of revenue increases for 2015 and 2016 from the 2013 rate case.[151] The current fixed charge was increased from $9.00/month from the 2010 rate case stipulations which stipulated rates, with the approval of the GPSC, through

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[147] There are also specific administrative charges for residential pre-pay rate customers which are included in the fixed charge. "Electric Service Tariff: Residential Service Schedule: 'R-22'," Georgia Power, effective January 2016, https://www.georgiapower.com/docs/rates-schedules/residential-rates/2.10_R.pdf.

[148] *Ibid.*

[149] "Electric Service Tariff: Fuel Cost Recovery Schedule: 'FCR-24'," Georgia Power, effective January 2016, https://www.georgiapower.com/docs/rates-schedules/common/10.40_FCR.pdf.

[150] Georgia Public Service Commission, *Order Adopting Settlement Agreement*, Docket No. 36989, December 23, 2013, http://psc.state.ga.us/factsv2/Document.aspx?documentNumber=151108.

[151] Georgia Public Service Commission, *Order Approving the 2015 Rate Update Stipulation,* Docket No. 36989, February 24, 2015, http://psc.state.ga.us/factsv2/Document.aspx?documentNumber=157212; Georgia Public Service Commission, *Order Approving the 2016 Rate Update Tariffs with Modification*, Docket No. 36989, December 22, 2015, http://psc.state.ga.us/factsv2/Document.aspx?documentNumber=161450.

2013.[152] The GPSC required that Georgia Power file its next general rate case by July 1, 2016.[153] However, in April 2016, Georgia Power announced that they would maintain the current electric rates through 2019.[154] This decision was in light of an agreement voted on by the GPSC related to the merger of Southern Company, Georgia Power's parent company, and AGL Resources.

[152] Georgia Public Service Commission, *Order Modifying Demand Side Management Tariffs and Approving Updated Base Tariffs*, Docket No. 31958, December 20, 2012, pp. 1-3, 4-5, http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=145296; Georgia Public Service Commission, *Compliance Filing*, Docket No. 31958, December 21, 2012, 2.10_R-19.doc, http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=145331.

[153] Georgia Public Service Commission, *Order Adopting Settlement Agreement*, Docket No. 36989, December 17, 2013, p. 16, http://psc.state.ga.us/factsv2/Document.aspx?documentNumber=151108.

[154] "Georgia Power base electric rates to remain flat through 2019," Georgia Power news release, April 14, 2016, https://www.georgiapower.com/docs/about-us/news/2016-04/GeorgiaPower-base-electric-rates.pdf.

III. WEST OTHER THAN CALIFORNIA

A. PacifiCorp M

California, California Public Utility Commission
Idaho, Idaho Public Utility Commission
Oregon, Oregon Public Utility Commission
Utah, Utah Public Service Commission
Washington, Washington Utilities and Transportation Commission
Wyoming, Wyoming Public Service Commission

PacifiCorp provides service to customers in six different states through the following operating companies: Rocky Mountain Power in Utah ("RMP-U"), Wyoming ("RMP-W"), and Idaho ("RMP-I") and Pacific Power & Light in Washington ("PP&L-W"), Oregon ("PP&L-O"), and California ("PP&L-C").[155] PacifiCorp's fixed charges are not limited to specific cost categories except in Washington and Utah, where policies limit residential fixed charges to customer-related costs. PacifiCorp often advocates for fixed charges that include customer service and distribution costs. Utah, Wyoming, Washington, and Idaho all use embedded costs to estimate fixed costs while California and Oregon use marginal costs. Marginal costs are estimated for new and existing customers for all categories in Oregon and for all categories except for transformer, meter, and service costs in California. PacifiCorp indicates that per the preference of the California Public Utilities Commission ("CPUC") and the Office of Ratepayer Advocates ("ORA"), marginal costs of the transformer, meters, and service costs are applicable to new customers only.[156] In Oregon and California, PacifiCorp states that annual economic carrying charges are only applied to fixed costs and are generally only used in the context of a marginal cost of service study.[157] In Oregon and California, where it employs marginal costs, PacifiCorp uses the relative percentages of functionalized marginal cost to allocate embedded revenue requirements by function.

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[155] "Company Overview," PacifiCorp, accessed February 27, 2016, http://www.pacificorp.com/about/co.html.

[156] See for example, Division of Ratepayer Advocates, California Public Utilities Commission, *Testimony on San Diego Gas & Electric Company's 2012 General Rate Case, Phase 2*, Docket A.11-10-002, May 18, 2012, p. 3. "DRA recommends that the Commission adopt marginal customer costs based on 'New Customer Only' ('NCO') methodology, which the Commission has adopted in nearly all litigated marginal cost decisions since 1992."

[157] These charges include levelized income and property taxes, are based on the expected life for the equipment in consideration, and include a present value cost or removal at the end of the useful life.

PacifiCorp uses the same cost of service study for both rate design and revenue allocation. However, the final revenue allocation or rate design may not correspond exactly to the costs estimated by the study, as rate impact is also considered. In general, PacifiCorp's uses the cost of service study as a guide for determining rates. In Wyoming, PacificCorp must set proposed rates within 99 to 101 percent of the cost of service for each class.[158] In Oregon, base rates must collect the cost of service; however, a rate mitigation surcharge or surcredit is used to mitigate large bill impacts within a rate case. PacifiCorp uses cost of service studies to assign costs to customer classes. Most of PacifiCorp's costs of service are joint costs. The utility allocates these costs among customer classes based on each class's relative share of measurable cost-defining service characteristics such as kWh, peak demand in kW, or customer count. Most of the residential fixed costs are recovered through energy rates rather than fixed charges, while most of the fixed costs for non-residential customers are recovered through demand or facilities charges. PacifiCorp has fixed charges for residential and non-residential customers. PacificCorp does not fully recover fixed costs through fixed charges in any of the states in which the utility provides service. Additionally, PacifiCorp has fixed charges that are not used to reduce tier 1 rates exclusively.

PacifiCorp does not consider differences in fixed costs within the residential customer class except in Idaho. In Idaho, PacifiCorp has two residential classes: one for customers who have opted into an optional TOU[159] and another that includes all other residential customers. These two residential classes have different fixed charges based on different metering costs and a different number of customers per transformer. Wyoming and Idaho do not provide low-income bill assistance. California provides a low-income discount as a percentage discount off the entire bill. In Washington, a low-income discount is applied November through April to energy usage over 600 kWh.[160] In Oregon, low-income assistance is provided by an outside agency. In Utah, low-income customers are provided a fixed monthly bill credit.

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[158] Wyoming Public Service Commission, *Finding of Fact, Conclusions of Law, Decision and Order Nunc Pro Tunc*, Docket No. 20000-446-ER-14, January 23, 2015, p. 42, https://dms.wyo.gov/OpenAttachment.aspx?file=aellio_22677_123201584804AM_20000-446-22677.pdf.

[159] The optional TOU residential class rate primarily benefits larger customers.

[160] The discount is based on the customers' income as a percentage of federal poverty level and is limited to 4,720 customers.

RMP-Utah has a residential fixed charge of $6.00/month for single-phase and $12.00/month for three-phase residential customers.[161] In Phase 2 of RMP-U's most recent rate case, for which a decision was issued in June 2010, the Utah Public Service Commission ("UPSC") approved an increase in the residential customer charge.[162] RMP-U had proposed an increase of the fixed customer charge to $4.45/month, from $3.00/month;[163] however, the UPSC approved a charge of only $3.75/month.[164] RMP-U also proposed that the UPSC reconsider costs recovered by the customer charge, suggesting that the UPSC consider residential share of distribution costs and revenue volatility when deriving fixed customer charges.[165] The UPSC declined to change the methodology it uses to classify fixed costs considered in the fixed customer charge.[166] The utility states that all increases to the residential fixed customer charge have been stipulated since the above rate case decision resulting in the current residential fixed charge rates.

PP&L-Washington has a residential fixed charge of $7.75/month.[167] In PP&L-W's last rate case, both the Washington Utilities and Transportation Commission ("WUTC") Staff and the utility proposed to increase PP&L-W's residential fixed charge from $7.75/month.[168] PP&L-W proposed an increase to $14.00/month and WUTC Staff proposed an increase to $13.00/month "to allow the company more stable revenues and in support of its proposal to add a third volumetric block to encourage conservation and distributed generation."[169] PP&L-W also requested an increase to the low-income assistance program by $1.00/month, which would increase the fixed charge to

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[161] "Electric Service Schedule No. 1 Residential Service – State of Utah," Rocky Mountain Power, effective September 1, 2014, https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.

[162] Utah Public Service Commission, *Report and Order on Rate Design*, Docket No. 09-035-23, June 2, 2010, http://www.psc.state.ut.us/utilities/electric/elecindx/2006-2009/documents/669350903523ROord.pdf.

[163] *Id.*, p. 20.

[164] *Id.*, p. 31.

[165] *Id., pp. 29-31*

[166] *Ibid.*

[167] "Schedule 16 Residential Service," Pacific Power & Light, effective October 4, 2016, https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Washington/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.

[168] Washington Utilities and Transportation Commission, *Final Order Rejecting Tariff Sheets; Resolving Contested Issues; Authorizing and Requiring Compliance Filings*, Docket No. UE-140762, March 25, 2015, http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=140762.

[169] *Id.*, p. 86.

$8.75/month.[170] The WUTC ultimately rejected the increase in residential fixed customer charges on March 25, 2015, despite the Staff and PP&L-W proposals, stating that it was "not prepared to move away from the long-accepted principle that basic charges should reflect only 'direct customer costs,'" of which it did not consider the proposed distribution costs to be a part.[171] The WUTC also stated that it recognizes decoupling as the preferred approach for residential rate design and suggests that PP&L-W consider decoupling in the future.[172] In the rate case, PP&L-W demonstrated that a residential fixed charge of $28.00/month could be justified based on the cost of service study indicating that approximately 28 percent of PP&L's fixed residential costs are recovered through the fixed charge. [173]

RMP-Wyoming has a residential fixed charge of $20.00/month.[174] On January 23, 2015, the Wyoming Public Service Commission ("WPSC") rejected RMP-W's proposed fixed charge increase from $20.00/month to $22.00/month, based on opponent testimony.[175] One opponent stated that because "residential energy consumption is declining" and "residential costs remained flat" the request should be denied.[176]

RMP-Idaho has a standard residential fixed charge of $5.00/month[177] and a residential optional TOU fixed charge of $14.00/month.[178] In RMP-I's 2011 rate case, the utility proposed to remove

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170 *Ibid.*

171 *Id.*, p. 91.

172 *Id.*, pp. 92-94.

173 Washington Utilities and Transportation Commission, *Direct Testimony of Joelle R. Steward*, Docket No. UE-140762, May 1, 2014, pp. 19, 23 http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=140762.

174 "Residential Service Schedule 2 – P.S.C. Wyoming No. 16," Rocky Mountain Power, effective January 13, 2016, https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Wyoming/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.

175 Wyoming Public Service Commission, *Finding of Fact, Conclusions of Law, Decision and Order Nunc Pro Tunc*, Docket No. 20000-446-ER-14, January 23, 2012, p. 42, https://dms.wyo.gov/OpenAttachment.aspx?file=aellio_22677_123201584804AM_20000-446-22677.pdf.

176 *Id.*, p. 33.

177 "Electric Service Schedule No. 1 Residential Service – State of Idaho," Rocky Mountain Power, effective January 1, 2016, https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Idaho/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.

the minimum charge requirement of $10.64/month and replace it with a residential fixed charge of $12.00/month.[179] The Idaho Public Utilities Commission ("IPUC") Staff supported the replacement of the minimum charge with a fixed charge; however, the Staff recommended a lower fixed charge of $5.00/month, citing similar approvals for other Idaho utilities.[180] The IPUC approved the replacement of the $10.64/month minimum bill with the implementation of the $5.00/month residential fixed charge as well as the retention of the $14.00/month residential TOU fixed customer charge.[181]

PP&L-Oregon has a residential fixed charge of $9.50/month[182] and PP&L-California has a residential fixed charge of $7.07/month.[183] The legal limit to the fixed charge in California is $10.00/month, subject to a CPI adjustment.[184] PacifiCorp indicated that it has not been involved in any recent orders which deliberated fixed charges for PP&L-O or PP&L-C.

Continued from previous page

178 "Electric Service Schedule No. 36 Optional Time of Day – Residential Service – State of Idaho," Rocky Mountain Power, effective September 15, 2006, https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Idaho/Approved_Tariffs/Rate_Schedules/Optional_Time_of_Day_Residential_Service.pdf.

179 Idaho Public Utilities Commission, *Order*, Case No. PAC-E-10-07, Order No. 32196, February 28, 2011, p. 45.

180 *Id.*, p. 48.

181 *Ibid.*

182 "Schedule 4 Residential Service Delivery Service – Oregon," Pacific Power & Light, effective January 1, 2014, https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Residential_Service_Delivery_Service.pdf.

183 "Schedule No. D Residential Service," Pacific Power & Light, effective April 24, 2016, https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/California/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.

184 California Legislature, *Legislative Counsel's Digest*, Assembly Bill No. 327, p. 2, October 7, 2013, http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201320140AB327.

B. Portland General Electric DM
Oregon, Oregon Public Utility Commission

Portland General Electric's ("PGE") fixed costs related to fixed charges include customer service costs, uncollectibles, and the customer-related portion of the service lateral and transformer. The utility uses marginal costs to estimate fixed costs and uses the same MCOSS for rate design and revenue allocation. PGE uses EPMC to scale unbundled fixed costs which are estimated for all customers. The utility defines commercial and industrial classes first by size, then, within the size category, by delivery voltage. The utility defines residential classes and some other classes by end-use, for example irrigation, pumping, and outdoor lighting. The utility has fixed charges for residential and non-residential customers. For customers over 200 kW, PGE collects 100 percent of fixed costs through the monthly fixed charge; however, for smaller customers, PGE recovers less than 100 percent.

PGE has decoupling in place for residential customers, which, the utility states, has resulted in significant difficulty in increasing its fixed basic charge. PGE's decoupling is subject to weather normalization, exposing the utility to subsequent risk. In defining annualized costs, PGE uses the assets life cycle for each distribution facility. For operating and maintenance costs, PGE uses the test period costs by FERC account and allocates some of the other operating and maintenance costs. PGE's fixed charge methodology and application is consistent with the practice of limiting fixed costs to customer-related costs. PGE first implemented a residential fixed charge in 1975 with the goal of recovering fixed customer-related costs using a monthly fixed charge.

The current residential basic charge is $10.50/month as of August 1, 2016.[185] The utility does not provide low-income discounts. The residential fixed basic charge recovers 49 percent of customer-related residential fixed costs. This current rate was increased from $10.00/month in a settlement approved by the Oregon Public Utility Commission ("OPUC") in November 2015.[186] PGE had originally proposed increasing the residential fixed charge rate to $11.00/month.[187] OPUC Staff noted that the $11.00/month proposed fixed charge did not cover PGE's marginal

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185 "Schedule 7 Residential Service," Portland General Electric, effective August 1, 2016, https://www.portlandgeneral.com/our-company/regulatory-documents/tariff.

186 Oregon Public Utility Commission, *Order*, Docket No. UE 294, Order No. 15 356, November 3, 2015, pp. 10-11, http://apps.puc.state.or.us/orders/2015ords/15-356.pdf.

187 *Ibid.*

customer costs and although they recommended a lesser fixed charge increase of $10.50/month, that this rate should be "contingent on [residential] volumetric prices not decreasing below current volumetric prices as a result of the increase in the basic charge."[188]

[188] Oregon Public Utilities Commission, *Joint Testimony in Support of the Second Partial Stipulation*, Docket No. UE 294, August 28, 2015, pp. 18-19, http://edocs.puc.state.or.us/efdocs/HAR/ue294har17952.pdf.

C. Public Service Company of Colorado
Colorado, Colorado Public Utilities Commission

The Public Service Company of Colorado's ("PSCC") fixed costs used to estimate fixed charges include the investment costs of meters and service drops, meter reading, customer service and billing expenses, and some allocated overhead costs. PSCC uses embedded costs to estimate fixed costs. The utility uses the same ECOSS for revenue allocation and rate design; however, rate design is also influenced by marginal costs and other rate-design goals. PSCC's cost of service studies rely on the traditional process of functionalizing, classifying, and allocating costs. For purposes of the cost of service studies, the utility does not identify costs as being joint, common, or separable with the exception of asset costs which are assigned to specific classes including street and traffic signal lighting assets. PSCC considers whether costs are variable or fixed when allocating the costs for cost of service study purposes.

The utility's general fixed charges methodology and application is consistent with the practice of limiting fixed charges to customer-related costs. However, the utility points out that in various proceedings with two-part rates, the collection of 100 percent of capacity-related costs has been problematic when no minimum system is included. PSCC uses two-part tariffs for residential customers in which capacity-related fixed costs are recovered through energy charges. PSCC has fixed charges for both residential and non-residential customers.

The utility has two residential customer rate schedules, general service and demand. The general residential monthly fixed charge is currently $7.71/month which includes a $6.75/month base rate scaled up using a General Rate Schedule Adjustment ("GRSA") of 14.9 percent.[189] The residential demand monthly fixed charge includes a base rate of $12.25/month which is then scaled up by the GRSA.[190] PSCC provides low-income bill assistance through a program financed by all of the utility's customers; however, there is no rate discount included in the program. The utility's fixed charges currently cover all customer-related fixed costs. The utility states that the

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[189] The GRSA is an adjustment that PSCC uses to collect more base revenue without a rate-design case. "Colorado – Electric, Electric Tariff Index," Public Service Company of Colorado, effective March 6, 2014 and effective May 8, 2015, Sheet No. 30 and Sheet No. 106, http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/CO/psco_elec_entire_tariff.pdf.

[190] *Id.*, effective July 1, 2012, Sheet No. 33.

fixed monthly charges have changed in response to the changing level of customer-related costs. PSCC's customer-related costs are currently declining and the utility expects that the fixed charges will also likely decline.

In PSCC's last rate case, the utility proposed a three-year rate plan for 2015 through 2017, which ended in a settlement agreement approved by the Colorado Public Utilities Commission ("CPUC") on January 23, 2015.[191] The settlement resulted in "moderate rate increases in 2015 and 2016 and a small decrease in 2017."[192] PSCC originally proposed increasing the general residential schedule fixed charges to $8.81/month;[193] however, the approved tariffs proposed a fixed general residential customer charge of $6.75/month for all three years in the rate plan, which it is currently.[194] As required by the last rate case, the PSCC submitted a new Phase II electric rate case in January 2016 addressing rate design and pricing structure.[195] In the 2016 rate case, PSCC initially proposed to decrease the standard residential fixed charge to $5.78/month.[196] This proposed decrease was a result of a new PSCC cost of service study that fulfills one purpose of the Phase II rate case to reallocate among the customer classes the revenue requirement approved by the Phase I rate case.[197] The PSCC is currently awaiting the approval of a settlement with the

[191] Colorado Public Utilities Commission, *Settlement Agreement*, Proceeding No. 14AL-0660E, January 23, 2015.

[192] "Colorado 2015-2017 Electric Rate Case: Investing for the Future, Delivering Value Today," Xcel Energy, accessed on February 18, 2016.

[193] Colorado Public Utilities Commission, *Advice No. 1672 - Electric*, Proceeding No. 14AL-0660E, June 17, 2014, Sheet No. 20, http://www.xcelenergy.com/staticfiles/xe/Marketing/Files/CO-Regulatory-Advice-Letter-1672.pdf.

[194] Colorado Public Utilities Commission, *Settlement Agreement*, Proceeding No. 14AL-0660E, January 23, 2015, Attachment B, pp. 47, 50, 53.

[195] "2016 Colorado Phase II Electric Rate Case," Xcel Energy, 2016, accessed February 22, 2016, http://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-Phase2-Elec-Rate-Case-Fact-Sheet.pdf.

[196] "Electric Rates – Residential General Service Schedule R," Schedule of Rates for Electric Service Available in the Entire Territory Served by Public Service Company of Colorado, Public Service Company of Colorado, effective February 25, 2016, Sheet No. 30, http://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/PSCo-Phase-II/Rates-PSCo-Phase-II-2016-Proposed-Tariff-No.8.pdf.

[197] "Important Notice about Your Energy Prices and Electric Service," Xcel Energy news release, January 25, 2016, http://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/PSCo-Phase-II/CO-Rates-Phase2-Customer-Notice.pdf.

CPUC which would result in a residential fixed charge of $5.39/month due to the decline in the costs of metering and other expenses.

IV. CALIFORNIA

A. Glendale Water & Power

California, Glendale City Council

Glendale Water and Power ("GWP") has two different residential customer rates: one standard residential service rate and another optional TOU residential service rate.[198] The standard residential fixed charge is approximately $11.00/month and the optional TOU residential fixed charge is approximately $24.00/month.[199] GWP offers qualifying low-income customers a $13.00 monthly customer bill discount.[200] GWP has fixed charges for both residential and non-residential customers.[201] The current rates are part of a five-year rate plan proposed by GWP and approved by the Glendale City Council on August 13, 2013.[202] The first rate increase became effective on September 13, 2013 and successive increases were approved on July 1 of the four subsequent years of the plan.[203] The largest rate increases occur in the first three years of the plan with lower increases in the final two years.[204] The residential fixed customer charge remains relatively constant with the increase coming primarily from increased energy charges.[205]

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198 Glendale Water and Power also has two residential rates for distributed generation customers which offer the same corresponding fixed charges as the standard residential service schedule and TOU residential service schedule. See "Residential Electric Rates," Glendale Water & Power, accessed October 24, 2016, http://www.glendaleca.gov/government/departments/glendale-water-and-power/rates/residential-electric-rates.

199 "Glendale Care," Glendale Water & Power, accessed October 24, 2016, http://www.glendaleca.gov/glendale-care.

200 "Community Meeting Proposed Electric Rate Presentation," Glendale Water & Power presentation, p. 33, http://www.glendaleca.gov/home/showdocument?id=3907.

201 "Rates," Glendale Water & Power, accessed December 14, 2015, http://www.glendaleca.gov/government/city-departments/glendale-water-and-power/rates.

202 "Management Discussion and Analysis – Electric Utility," Glendale Water & Power, pp. 5-6, http://www.glendaleca.gov/home/showdocument?id=26152. See also *Id.*, pp. 21-35.

203 *Id.*, p. 6.

204 *Ibid.* See also "Community Meeting Proposed Electric Rate Presentation," Glendale Water & Power presentation, p. 34, http://www.glendaleca.gov/home/showdocument?id=3907.

205 *Ibid.*

B. Modesto Irrigation District

California, Modesto Irrigation District Board of Directors

Modesto Irrigation District's ("MID") total fixed costs include transmission and distribution, debt service, customer account expenses, and power plant fixed costs; however, only customer-related expenses are included in the monthly fixed customer charge. MID uses embedded costs to estimate fixed costs and the utility uses the same ECOSS for both rate design and class revenue allocation. The ECOSS allocates joint costs to either fixed or variable costs. For revenue allocation, customer classes are defined based on size and use. Costs for each of the customer classes are determined by allocators such as number of meters, contribution to peak demand, and other allocation factors. When defining annualized costs, MID uses its depreciation schedule as a basis to allocate plant costs.

MID has had fixed charges for over 20 years. Throughout that period, it has utilized the practice of limiting the definition of fixed costs to customer-related costs when calculating fixed charges. The utility has fixed charges for residential and non-residential customers.[206] Unlike residential customers, some non-residential customers are subject to demand changes, which contribute to fixed cost recovery.

The residential fixed charge is currently $20.00/month as of January 1, 2016,[207] which was increased from $12.50/month.[208] Low-income customers who enroll in the MID CARES program receive a discount of 60 percent on the monthly fixed charge and a discount of 23.1 percent on the first 850 kWh of electric usage.[209] MID's Board Agenda Report, outlining the utility's most recent residential fixed charge, states, "the outline the staff has proposed will help align the rates closer to the cost structure by increasing the monthly fixed charge and reducing the energy

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206 "Electric Rate Schedules and Service Rules," Modesto Irrigation District, accessed December 14, 2015, http://www.mid.org/tariffs/default.html.

207 "Electric Rate Schedule D Residential Service," Modesto Irrigation District, effective January 1, 2016, http://www.mid.org/tariffs/Rates/D_RESIDENTIAL.pdf.

208 "2016 Rate Workshop," Modesto Irrigation District presentation, October 13, 2015, p. 13, http://www.mid.org/about/newsroom/notices/documents/2016ResidentialRateDesign_10032015.pdf.

209 "Electric Rate Schedule D Residential Service," Modesto Irrigation District, effective January 1, 2016, http://www.mid.org/tariffs/Rates/D_RESIDENTIAL.pdf.

charge."[210] MID decreased exclusively first tier rates (500 kWh or less) in order to make the increased residential fixed customer charge revenue-neutral. Before the last rate increase, 60 percent of MID's costs were fixed and only 20 percent of revenue was collected through fixed charges, with the residential class collecting only 9 percent of revenues through fixed charges.[211]

[210] "Board Agenda Report – Public Hearing: 2016 Electric Retail Rate Restructure," Modesto Irrigation District, November 17, 2015, p. 1, http://mid.granicus.com/MetaViewer.php?view_id=1&clip_id=118&meta_id=9777.

[211] "2016 Rate Workshop," Modesto Irrigation District presentation, October 13, 2015, p. 3, http://www.mid.org/about/newsroom/notices/documents/2016ResidentialRateDesign_10032015.pdf.

C. Riverside Public Utilities
California, City Council Board of Public Utilities

Riverside Public Utilities ("RPU") has two fixed charges, a Customer Charge and a Reliability Charge.[212] The Customer Charge is designed to recover fixed costs including meter reading, billing, customer service and administration, while the Reliability Charge is designed to recover debt service related costs. The Reliability Charge is "a flat charge assigned to each electric meter that pays for major energy infrastructure projects including transmission and local energy generation."[213]

The utility has two different residential class tariffs including a standard domestic service class and a TOU-tiered domestic service class.[214] The fixed Customer Charge for both residential classes is $8.06/month.[215] The Reliability Charge is the same for all of the residential schedules and is based on current: $10.00/month for current less-than-or-equal-to-200 amps, $20.00/month for current between-101-and-200 amps, $40.00/month for current between-201-and-400 amps, and $60.00/month for current over-400 amps.[216] Sixty-nine percent of RPU's costs are fixed,

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[212] "Riverside Public Utilities Finance 101 – City Council Workshop," Riverside Public Utilities presentation, September 1, 2015, p. 76, http://www.riversideca.gov/utilities/pdf/2015/Finance-101.pdf.

[213] "Bill Explanations," Riverside Public Utilities, accessed December 20, 2015, http://riversideca.gov/utilities/mybill/Front_Of_Bill_Explanations.pdf.

[214] RPU also had a residential TOU domestic service class rate schedule which was closed to new customers effective December 14, 2010 and closed existing customers effective January 1, 2016. See "Schedule D-T-O-U Domestic Time-of-Use Service," Turlock Irrigation District, effective December 14, 2010, http://www.riversideca.gov/utilities/pdf/2010/Domestic%20TOU%20-%20cc%2012-14-2010-%20Clean-%20effective%2012-14-10.pdf.

[215] The standard domestic service Customer Charge was adopted by the Board of Public Utilities on February 15, 2013 and was approved by City Council and became effective March 26, 2013. "Schedule D Domestic Service," Riverside Public Utilities, effective March 26, 2013, http://www.riversideca.gov/utilities/pdf/2013/Electric%20Schedule%20D-%20clean%202-1-2013.pdf; The TOU-tiered domestic service Customer Charge was adopted by the Board of Public Utilities on August 2, 2013 and was approved by City Council and became effective September 10, 2013. "Schedule D Domestic Service," Riverside Public Utilities, effective September 10, 2013, http://www.riversideca.gov/utilities/pdf/2013/Schedule_D-TOU-_Tiered-_effective_09-10-13.pdf.

[216] *Ibid.*

while only fifteen percent of total revenues are fixed.[217] The utility indicates that the ideal balance is one in which the percentage of fixed revenues matches that of fixed costs.[218]

[217] "Utility 2.0 Joint Meeting – Utility 2.0 Plan," Riverside Public Utilities presentation, August 28, 2015, p. 71, http://www.riversideca.gov/utilities/pdf/2015/8-28-2015-Complete-Presentation.pdf.

[218] *Id.*, p. 70.

D. Sacramento Municipal Utility District M
California, Sacramento Municipal Utility District Board of Directors

SMUD's fixed charge, called the System Infrastructure Fixed Charge ("SIFC"), is designed to recover fixed costs including the cost of metering, billing, customer services, transformers, poles, wires, other electric equipment used to provide reliable electric service.[219] SMUD uses marginal costs to estimate fixed costs and uses the same MCOSS for class revenue allocation and rate design. Marginal costs are estimated for all customers.[220] SMUD defines customer classes for revenue allocation by type and capacity size. The types are residential, commercial, lighting, and agriculture with subgroups for different capacity sizes, for example, small commercial (<= 20 kW), small commercial (21-299 kW), and medium commercial (300-499 kW). SMUD uses marginal cost to determine revenue requirement targets by rate class and uses a scaling mechanism to adjust revenue.[221] SMUD indicates that the economic carrying charge includes expected useful life of the assets, assuming that distribution and transmission equipment would require period replacement, following the industry-standard survival curves, and also taking into account administrative and general loading. SMUD follows the practice of limiting fixed costs to customer-related costs when designing fixed charges. SMUD has fixed charges for residential and non-residential customers.

SMUD has a single residential customer class. The current residential fixed charge as of January 1, 2016, is $18.00/month,[222] representing one step in a five-year plan to restructure the residential fixed charge.[223] The plan includes an annual increase of $2.00/month from January

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[219] "Addendum to the General Manager's Report and Recommendation on Rates and Services – Addendum No. 2," 2011 General Manager's Report and Recommendation on Rates and Services, Sacramento Municipal Utility District Publication, June 16, 2011, p. 6, https://www.smud.org/assets/documents/pdf/GM-Rate-Report-Addendum-2-06-16-11.pdf.

[220] *Id.*, pp. 6-7.

[221] SMUD indicates that the utility did not make such an adjustment in Addendum 2 to the 2011 General Manager's report. See footnote 182.

[222] "Residential Service Rate Schedule R," SMUD, effective January 1, 2016, https://www.smud.org/assets/documents/pdf/1-R.pdf.

[223] "Addendum to the General Manager's Report and Recommendation on Rates and Services – Addendum No. 2," 2011 General Manager's Report and Recommendation on Rates and Services, Sacramento Municipal Utility District Publication, June 16, 2011, pp. 6-10, https://www.smud.org/assets/documents/pdf/GM-Rate-Report-Addendum-2-06-16-11.pdf.

2013 to January 2017, when the residential fixed charge will reach $20.00/month.[224] The five-year plan was approved and adopted by the SMUD Board of Directors on August 4, 2011.[225] In addition, SMUD has an energy assistance program[226] in which the residential fixed charge is reduced to $7.50/month, which was increased from the 2011 rate of $3.50/month.[227] Before the implementation of the five-year rate plan, the residential fixed charge was $7.20/month, which recovered less than 30 percent of the residential customer-related fixed costs.[228] The SMUD Staff is currently evaluating TOU rate structures and plans on making a proposal for a default TOU rate structure to the Board in 2018.

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224 *Id.*, p. 6. In addition, the utility notes that SMUD will no longer have a tiered rate structure by the end of the five-year plan in 2017.

225 "Resolution No. 11-08-06," Sacramento Municipal Utility District, August 4, 2011, p. 16, https://www.smud.org/assets/documents/pdf/Resolution_11-08-06.pdf.

226 SMUD's energy assistance program is for qualifying customers under 200 percent of the federal poverty level.

227 *Id.*, p. 6. See also, Low-income assistance, SMUD, accessed on February 22, 2016, https://www.smud.org/en/residential/customer-service/rate-information/low-income-assistance.htm.

228 "Addendum to the General Manager's Report and Recommendation on Rates and Services – Addendum No. 2," 2011 General Manager's Report and Recommendation on Rates and Services, Sacramento Municipal Utility District Publication, June 16, 2011, p. 7, https://www.smud.org/assets/documents/pdf/GM-Rate-Report-Addendum-2-06-16-11.pdf.

E. Turlock Irrigation District

California, Turlock Irrigation District Board of Directors

TID's fixed charge is based on the fixed costs of billing and collection, meter reading, service drops, final line transformers, general and administrative expenses, and other related expenses.[229] Distribution costs for meters, and customer installations are also included in the fixed customer charge.[230] TID's fixed costs are estimated using embedded costs in an ECOSS. The utility's ECOSS includes the fixed costs of distribution, discussed above, in calculating fixed costs. TID indicates that it does not used annualized carrying costs. The utility defines and allocates costs to customer classes by energy load, demand load, coincident and non-coincident demand, seasonal demand, and number of customers.[231] TID has fixed charges for residential and non-residential customers.[232] The utility points out that similar to many publicly-owned utilities, TID has had customer charges for decades.

TID has one residential class and the current residential fixed customer charge is $17.00/month.[233] TID also offers assistance to low-income customers which includes a discount of $11.00/month and an additional discount of 15 percent on the customer's first 800 kWh of energy usage.[234] The increased residential fixed charge was approved by the TID Board of Directors as part of the 2015 budget approval process and became effective January 1, 2015.[235]

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[229] "Cost of Service," TID Cost of Service 2014.xls, Turlock Irrigation District workpaper, 2014. TID's document, TID Cost of Service 2014.xls, was provided as part of the public information survey request, but is not published online.

[230] *Ibid.*

[231] "Allocators," TID Cost of Service 2014.xls, Turlock Irrigation District workpaper, 2014.

[232] "Rates, Rules, and Regulations," Turlock Irrigation District, accessed December 14, 2015, http://www.tid.org/2015-electric-rates.

[233] "Schedule DE Domestic Service," Turlock Irrigation District, effective January 1, 2015, http://www.tid.org/sites/default/files/documents/tidweb_content/schedule%20de%20(2015).pdf.

[234] "Energy Assistance Program," Turlock Irrigation District, effective January 1, 2015, http://www.tid.org/sites/default/files/documents/tidweb_content/Residential%20Service%20Energy%20Assistance%20Program.pdf.

[235] "Minutes of the Board of Directors Meeting of the Turlock Irrigation District," Turlock Irrigation District, December 9, 2014, p. 3, http://www.tid.com/sites/default/files/documents/news-resources/TID%20Board%20Minutes%20-%20December%209,%202014.pdf. See http://www.tid.org/2015-electric-rates for all electric rates approved by the Resolution No. 2014-104 effective January 1, 2015.

The residential fixed customer charge was increased from $11.00/month.[236] Subsequently, the Board also approved a reduction in energy charges.[237]

[236] "Rate Hearing for 2015 Rate Changes," Turlock Irrigation District presentation, December 2, 2014, p. 16. See http://www.tid.org/2015-electric-rates for all electric rates approved by the Resolution No. 2014-104 effective January 1, 2015.

[237] *Ibid.*

Appendix A: The Survey Instrument

F. Theoretical Support for Residential Fixed Charges

1) What cost categories do you include in fixed costs? Typically the following are included: metering, billing, and customer care. Sometimes the line drop and transformer are also included.
2) Do you include any capacity or demand-related costs in fixed charges?
3) Do you estimate fixed costs based on marginal or embedded costs?

G. Methodology for Calculating Fixed Charges

1) Are the same cost studies used for class allocation of revenue and the development of rate designs?
2) How do you define customer classes in revenue allocation?
    a. How do you justify assignment of costs to the customer/customer class?
3) If you use marginal costs to determine fixed costs:
    a. Do you use the Equal Percentage Marginal Costs (EPMC) or some other scaling mechanism to determine fixed charges?
    b. Are marginal costs only estimated for new customers?
4) Is there a difference in the collection of fixed costs from residential versus non-residential customers?
5) Are there differences in fixed costs within the residential customer class? If yes:
    a. What are the typical thresholds for defining a difference in cost of service for a specific customer group (i.e. single/multi-family, amperage of service panel, low income customers)?
    b. How are income-based discounts delivered, if any?
6) Are your revenues and sales decoupled? If they are decoupled, did you encounter difficulties in collecting fixed charges?
7) What are the magnitudes of your fixed charges? Have they changed over time? Are you expecting them to change further over time?
    a. Are there legal limits on these magnitudes?

i. Do fixed charges recover all fixed costs? If not, what percentage do they recover?

8) Do you have fixed charges for non-residential customers?
9) If you have a tiered (or block) rate structure, are fixed charges used exclusively to reduce tier 1 rates (*i.e.*, requirement for a composite tier 1)?

H. Follow-Up Questions

1) Would you please provide us with the documentation or a link to the most recent Commission Order regarding your fixed charges and any related Testimony or Work Papers?
2) What have you done to address the issue of joint costs? (i.e., The identification of assets that fall under fixed costs versus other types of costs)
3) Do you use marginal cost as a means of revenue allocation?
4) When defining annualized costs, what assumptions do you use in your assessment of carrying costs? For example, single asset life cycle versus perpetuity, replacements within the factor or external, etc. If you use such annualized carrying charges, is there a difference in approach and method when looking at fixed and variable costs?
5) Traditional regulatory context tends to suggest that fixed costs, expressed in dollars per month, are typically limited to customer related costs (for example, final line transformers, service drop, meter and related billing costs, etc.). Is this consistent and applicable to your practice of applying fixed charges? Also, for what reason did you apply fixed charges originally?

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MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules of governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	Case N^o. U-18255 ALJ Mark D. Eyster

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PROOF OF SERVICE

On the date below, an electronic copy of **the Direct Testimony of Jonathan Wallach on behalf of the Natural Resources Defense Council, Michigan Environmental Council, and Sierra Club with Exhibits NRD-1 through NRD-4** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

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Counsel for NRDC-MEC-SC

Date: August 29, 2017

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