Exhibit No.:	
Issues:	Demand-Side Programs
Witness:	John A. Rogers
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Rebuttal To Supplemental Testimony
File No.:	EO-2015-0055
Date Testimony Prepared:	July 15, 2015

MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

JOHN A. ROGERS

REBUTTAL TO SUPPLEMENTAL TESTIMONY

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

FILE NO. EO-2015-0055

Jefferson City, Missouri
July 2015

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as allowed by MEEIA	)))))	Case No. EO-2015-0055

AFFIDAVIT OF JOHN A. ROGERS

State of Missouri)
) ss.
County of Cole)

AFFIDAVIT

COMES NOW John A. Rogers and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached Rebuttal to Supplemental Testimony and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

John A Rogers

John A. Rogers

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 15th day of July, 2015.

Laura Distler

NOTARY PUBLIC

LAURA DISTLER
Notary Public, Notary Seal
State of Missouri
Cole County
Commission # 15203914
My Commission Expires June 21, 2019

JOHN A. ROGERS

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JOHN A. ROGERS

REBUTTAL TO SUPPLEMENTAL TESTIMONY

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FILE NO. EO-2015-0055

Q. Please state your name and business address.

A. My name is John A. Rogers, and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. What is your present position at the Missouri Public Service Commission ("Commission")?

A. I am a Utility Regulatory Manager in the Energy Unit of the Regulatory Review Division.

Q. Are you the same John A. Rogers that filed rebuttal testimony, surrebuttal testimony and supplemental direct testimony in this case on March 20, 2015, April 27, 2015, and July 9, 2015, respectively?

A. Yes, I am.

Q. Would you please summarize the purpose of your rebuttal to supplemental testimony?

A. I respond to certain aspects of the supplemental direct testimony of Union Electric Company's d/b/a Ameren Missouri Company's ("Ameren Missouri" or "Company") witness Daniel G. Laurent filed on June 30, 2015, specifically whether it provides sufficient support for Commission approval of the June 30, 2015 Non-Unanimous Stipulation and Agreement[1] ("Utility Stipulation"). My rebuttal to supplemental testimony will:

1. Present Staff's analysis of the customers' benefits and customers' costs - including the costs for the throughput disincentive and performance incentive - which are expected from implementation of the energy efficiency programs and the demand-side programs investment mechanism ("DSIM") contained in the Utility Stipulation;[2]
2. Comment on why the Company's proposed portfolio of energy efficiency programs and DSIM will likely result in very little, if any, net benefits for the vast majority of customers;
3. Respond to the Company's commitment to meet with the signatories to the Utility Stipulation during the first four months of 2016 to review potential additional energy efficiency opportunities to determine if it is possible to achieve savings above the targeted level in 2017 and 2018; and
4. Provide Staff's response to the proposed combined heat and power ("CHP") measure in the Utility Stipulation.

[1] Non-Unanimous Stipulation and Agreement with the following signatories: Ameren Missouri, Missouri Department of Economic Development – Division of Energy, Natural Resource Defense Council, Kansas City Power and Light Company, KCP&L Greater Missouri Operations Company, and United for Missouri.

[2] While Ameren Missouri is not required to provide a similar analysis, Staff believes Staff's analysis is instructive for the Commission during its consideration of the issues in this case.

CUSTOMERS' EXPECTED BENEFITS AND COSTS - INCLUDING THE COSTS FOR THE THROUGHPUT DISINCENTIVE AND PERFORMANCE INCENTIVE - FROM PROGRAMS AND DSIM IN UTILITY STIPULATION

Q. In your opinion, in the Utility Stipulation, does Ameren Missouri provide all the quantitative information and analysis the Commission needs when it considers whether or not to approve the proposed demand-side programs ("Utility Portfolio")?

A. No, it does not. In fact, it does not appear it was Mr. Laurent's intention to present a complete analysis since his supplemental testimony states: "The purpose of my testimony is to provide an overview of the additional savings targets, budget, programs and enhancements to the original MEEIA 2016-18 Plan, …"[3]

Q. What information is available for Commission consideration of the Utility Stipulation demand-side programs?

A. Table 1 and Table 2 of the Utility Stipulation present the demand-side programs which Ameren Missouri is requesting the Commission approve.

While the tables provide the energy savings, proposed budget, and total resource cost ("TRC") for each program, along with the total residential programs, total business programs and total utility portfolio, neither the tables nor the supporting supplemental testimony provide a complete analysis of the Customers' expected benefits and costs - including the costs for the throughput disincentive and performance incentive – which are expected as a result of the energy efficiency programs and the DSIM in the Utility Stipulation.

Q. Has Staff performed an analysis of customers' benefits and customers' costs - including the costs for the throughput disincentive and performance incentive - which are

[3] Laurent supplemental testimony at page 2, lines 3 – 5.

expected from implementation of the Utility Portfolio and DSIM in the Utility Stipulation since Ameren Missouri did not present such analysis in its testimony?

A. Yes. Schedule JAR-1 contains the results of Staff's analysis. Please note that all dollars in Schedule JAR-1 are discounted dollars using Ameren Missouri's weighted average cost of capital of 6.46%.

Q. Please discuss the process you used to perform the analysis contained in Schedule JAR-1.

A. Schedule JAR-1 has four separate sections which present the energy savings, demand savings, costs and benefits for the entire portfolio, residential programs and business programs for Commission-approved Cycle 1, the Cycle 2 application, and the Utility Stipulation including:

1. "Benefits and Costs Summary" reflects a summary of data Staff obtained from Ameren Missouri's filed documents and work papers, except for two exceptions in the Utility Stipulation column. Data is not available for the Utility Stipulation throughput disincentive or the 100% performance incentive amounts so Staff has estimated these amounts;[4]
2. "Customers as a Whole" represents all customers, i.e., residential customers and business customers combined, which is normally the only way these three market segments are analyzed;

[4] Each Utility Stipulation Throughput Disincentive amount and 100% Performance Incentive amount is estimated to be the Cycle 2 amount factored up or down based upon the relative "deemed" Energy Savings Target (GWh) amounts. For example: Utility Stipulation Portfolio Throughput Disincentive is $60 Million = $44 Million X (584 GWh / 426 GWh).

3. "Non-Participating Customers" represents all customers who do not participate directly - and in a meaningful way - in one or more programs;[5] and
4. "Participating Customers" represents all customers who participate directly in one or more programs, which in Staff's analysis is the same as the participant cost test[6] ("PCT").

Q. What do the letters and equations represent in the left hand column on Table 1?

A. But for the two exceptions described in my last answer, the individual letters represent values Staff obtained from Ameren Missouri's filed documents and work papers for Commission-approved Cycle 1, the Cycle 2 application, and the Utility Stipulation. The equations include the calculation of amounts related to customers' benefits and costs which are not available in the filed documents and work papers.

Q. In your opinion, what is the most significant data from Staff's analysis in Schedule JAR-1?

A. The most significant data from Schedule JAR-1 is presented in Schedule JAR-2, which contains graphical representations of the TRC, utility cost test ("UCT"), and benefit cost ratios for Cycle 1, the Cycle 2 application and the Utility Stipulation.

At a high level:

1. The TRC and UCT ratios[7] are significantly greater for Cycle 1 when compared to Cycle 2 which is primarily due to the much lower avoided costs of energy

[5] Because residential customers who are required to pay the Energy Efficiency Investment Charge (customers that are not qualified low income customers, which are exempt from paying the charge) will pay on average $6 per month and $216 total during the 36 months of Cycle 2, these customers will likely have to participate in more than just the residential lighting program to receive overall net benefits.

[6] Line j in Schedule JAR-1 provides the equations for calculating the PCT. 4 CSR 240-3.164(Q) provides a general definition of the participant test.

and demand used to value benefits from energy and demand savings for Cycle 2;[8]

2. Benefit cost ratios for participants have increased for Cycle 2 relative to Cycle 1 and for the Utility Stipulation relative to Cycle 2; and

3. Benefit cost ratios for customers as a whole and for customers who are non-participants have decreased significantly for Cycle 2 relative to Cycle 1 and have decreased for the Utility Stipulation relative to Cycle 2.

Q. What conclusion should the Commission draw from the various benefit cost ratios you present above?

A. The benefit cost ratios demonstrate that the Utility Stipulation provides for even higher costs and relatively lower net benefits for the customers as a whole and for non-participating customers than the Cycle 2 application, which is a concern.

VERY LITTLE, IF ANY, NET BENEFITS ARE EXPECTED FOR THE VAST MAJORITY OF CUSTOMERS

Q. Please respond to Mr. Laurent's statement: "Ameren Missouri recognizes the importance of being a good steward of the money that customers entrust to us to manage these programs."[9]

A. Mr. Laurent's Table 2 provides only the TRC values for programs in the Utility Stipulation. The TRCs for residential, business and portfolio levels are 1.31, 1.62, and 1.50, respectively. The TRCs in Table 2 suggest that if Ameren Missouri is successful in delivering all program services as planned and all deemed values are realized, then all

[7] Lines i and h in Schedule JAR-1 provide the equations for calculating the TRC and UCT, respectively, for Cycle 1, Cycle 2 and the Utility Stipulation. The complete definitions for TRC and UCT are contained in 4 CSR 240-3.164(1)(X) and 4 CSR 240-3.164(1)(Y), respectively.
[8] Rogers surrebuttal testimony Schedule JAR-S4.
[9] Laurent supplemental testimony at page 7, lines 1 – 2.

customers will benefit from the programs for which they pay. However, when factoring in the costs for the throughput disincentive and 100% performance incentive, Staff's analysis suggests that the majority of Ameren Missouri customers will likely receive very little, if any, overall net benefits from the programs and the DSIM in the Utility Stipulation.

Q. Please explain.

A. Approximately 87% of Ameren Missouri's customers are residential customers.[10] Schedule JAR-1 estimates that net benefits and benefit cost ratios are expected to be:

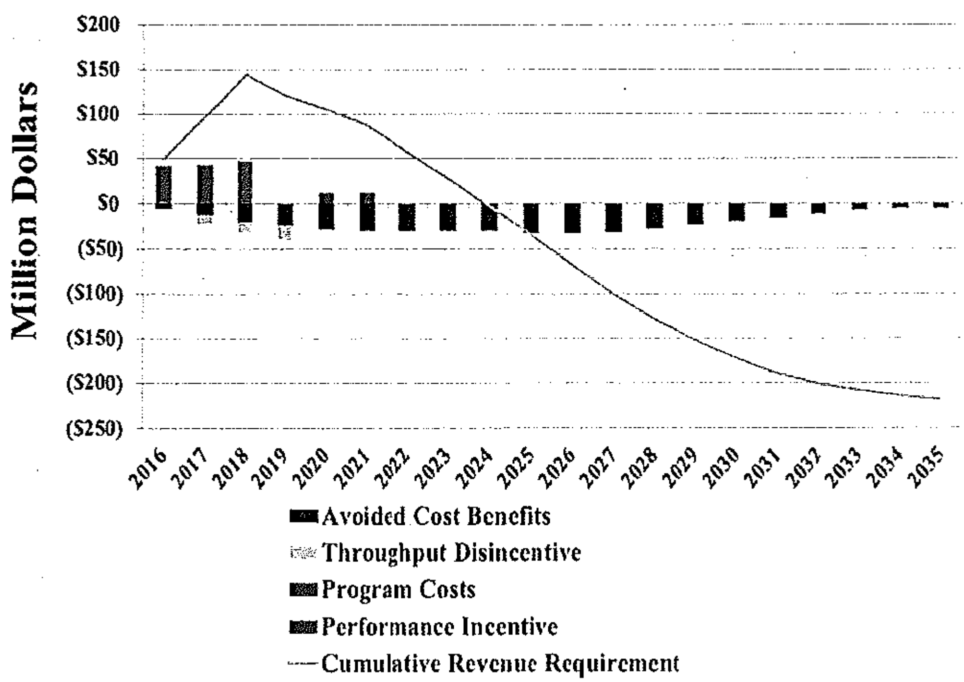
- $30 million and 1.34, respectively, for residential customers as a whole;
- $7 million and 1.06 for residential customers who are not expected to participate directly in programs, either because they have no awareness of the programs, have no interest in participating, have no need to participate, or they do not have the financial means to participate in a meaningful way by making a significant investment in energy efficiency measures; and
- $217 million and 5.84 for customers who participate directly in programs.

Staff's analysis estimates that residential customers who are non-participants will pay $112 million with the expectation that they will receive benefits of $119 million as a result of the programs and DSIM in the Utility Stipulation. Thus, as demonstrated in Schedule JAR-1, the expected net benefits non-participating residential customers are expected to receive are only worth an estimated $7 million and the benefit cost ratio is only 1.06.

Q. Is it a certainty that $7 million of net benefits will be realized by non-participating residential customers?

[10] Page 2 of Ameren Missouri's 2014 Annual Report (Tracking No. BMAR-2015-1678) specifies that 1,043,038 of Ameren Missouri's 1,202,283 total customers are residential customers. 1,043,038/1,202,283 = 0.868.

A. No. There is uncertainty and risk associated with expected customer benefits. Because expected benefits occur over the expected life of each measure (up to 20 years) and are based upon "deemed" energy and demand savings, which is a static baseline for determination of annual energy and demand savings from each energy efficiency measure, and "deemed" avoided costs for each energy efficiency measure, there are no guarantees on the return of net benefits. On the other hand, customers will certainly pay all program costs "contemporaneously" in years 1, 2 and 3 and will certainly pay any performance incentive award in years 5 and 6. The overall timing of customers' costs and benefits for all customers and all programs is illustrated in the following chart[11] from Ameren Missouri's Cycle 2 application.



[11] Data from Figure 3.9 on page 55 of the Cycle 2 Plan. All costs, benefits and cumulative revenue requirements in this chart are in millions of nominal dollars.

Q. Please provide any additional comments you would like the Commission to consider regarding Staff's analysis in Schedule JAR-1.

A. Using the information and data, or lack thereof, in Ameren's supplemental testimony, filed documents and work papers, only the benefits and costs for customers as a whole and for customers who are participants can be derived with accuracy. The benefits and costs for customers who do not participate in a meaningful way (non-participants) are calculated based upon the simplified assumptions which allocate all of the programs' costs and benefits, all of the throughput disincentive costs, and all of the 100% performance incentive costs to the non-participants. Nevertheless, it is instructive for the Commission to consider the analysis in Schedule JAR-1 and its resulting conclusion that there exists a significant possibility – if not a probability – that little to no net benefits will be realized by the majority of residential customers who pay for programs.

ADDITIONAL ENERGY EFFICIENCY OPPORTUNITIES TO DETERMINE IF IT IS POSSIBLE TO ACHIEVE SAVINGS ABOVE THE TARGETED LEVEL IN 2017 AND 2018

Q. Please respond to Mr. Laurent's testimony at page 4, lines 6 - 13:

> Ameren Missouri has agreed to meet with the signatories to the Stipulation during the first four months of 2016 to review potential additional energy efficiency opportunities to determine if it is possible to achieve savings above the targeted level in 2017 and 2018. Ameren Missouri *cannot commit* to a higher target level than the level set in the Stipulation, but it is certainly willing to continue to discuss this issue with the signatories to the Stipulation and determine if there are additional cost-effective measures or program changes which could be adopted that would result in the achievement of additional MWh savings or cost reductions.
>
> [Emphasis added]

A. Based upon the analysis presented in this testimony, it is Staff's opinion that a lack of commitment by Ameren Missouri largely mitigates any assurances that the majority of its customers will receive overall net benefits from the Utility Stipulation's programs for 2016, 2017 and 2018.

COMBINED HEAT AND POWER

Q. Please respond to Mr. Laurent's testimony at page 6, lines 3 – 5: "Based on input from the Division of Energy, the signatories to the stipulation are proposing to include Combined Heat and Power (CHP) as an eligible measure under the business custom program."

A. In Staff's opinion, it is questionable whether individual CHP projects can qualify as demand-side programs under MEEIA.[12] However, assuming individual CHP projects can qualify as demand-side programs under MEEIA, care must be taken before qualifying the projects under MEEIA and the Commission's MEEIA rules.[13] Sections 393.1075. 2. (3) and 4 CSR 240-20.093 (1) (L) define a demand-side program as '... any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the meter including, but not limited to, energy efficiency measures, load management, demand response, and interruptible or curtailable load." Section 393.1075.2.(4) and 4 CSR 240-20.093(1)(U) define energy efficiency as "measures that reduce the amount of electricity required to achieve a given end use." Commission rule 4 CSR 240-20.093(1)(K) defines demand response as "... measures that decrease peak demand or shift demand to off-peak periods." Under MEEIA rules, only the actual customer load curtailment amount would meet the requirements to qualify for an approved MEEIA demand response program. Therefore, for a CHP application, under the MEEIA rules, only the difference between the

[12] Section 393.1075,

[13] The Commission's rules promulgated as a result of the Missouri Energy Efficiency Investment Act of 2009 ("MEEIA") (Section 393.1075, RSMo, Supp. 2013) include Rules 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094, which were all first effective on May 30, 2011.

actual electrical consumption on the customer's side of the meter before and after the installation of a CHP system would be considered. Commission rule 4 CSR 240-3.164 identifies all of the demand-side program filing and submittal requirements for a program to be an approved as a MEEIA demand-side program. More specifically the rule requires the program to be considered and screened in a market potential study (4CSR 240-3.164 (2)(A)) and then the program must be demonstrated to be cost effective (4CSR 240-3.164 (2)(B)) with a TRC greater than 1.0. In addition, each demand side program must include all information required by 4CSR 240-3.164 (2)(C).

Q. Has the Company screened this proposed CHP measure and found it to be cost effective?

A. The Company has screened CHP (through its potential study and 2014 Chapter 22 triennial compliance filing[14]) as a measure and found it not to be cost effective as explained by Company witness Richard A. Voytas in his surrebutal testimony. Mr. Voytas states that "As table 4-3 shows, CHP is not cost effective for MEEIA 2016-2018. Relatively minor amounts of potential become cost effective in 2025."[15]

Q. How does the Utility Stipulation value CHP benefits?

A. Paragraph 13 of the Utility Stipulation states:

> For purposes of determining cost effectiveness, savings from CHP is defined as follows:
>
> Fuel Savings (FS) = (FT + FG) – FCHP
>
> FS – total fuel savings
> FT – avoided fuel use from on-site thermal production
> FG – avoided fuel use from purchased grid electricity
> FCHP – fuel use by the CHP system

[14] Case No. EO-2015-0084.
[15] Voytas surrebuttal testimony at page 81, lines 12 - 13.

> The determination of the cost effectiveness of CHP will also recognize any reduced electric capacity on the Ameren Missouri system as a result of the addition of CHP. Fuel from all sources is expressed in terms of BTUs.

Q. Does the Utility Stipulation approach to CHP with its fuel savings definition and recognition of reduced electric capacity on the Ameren Missouri system as a result of CHP comply with the MEEIA rules?

A. No. The Utility Stipulation approach to CHP gives no consideration as to whether the end-use consumption of electricity on the customer's side of the electric meter is reduced or modified.

Q. Does this conclude your testimony?

A. Yes.

Summary Analysis of Ameren Missouri MEEIA Cycle 1*, MEEIA Cycle 2 Application** and 6/30/2015 Utility Stipulation and Agreement*** (Millions of Discounted Dollars)

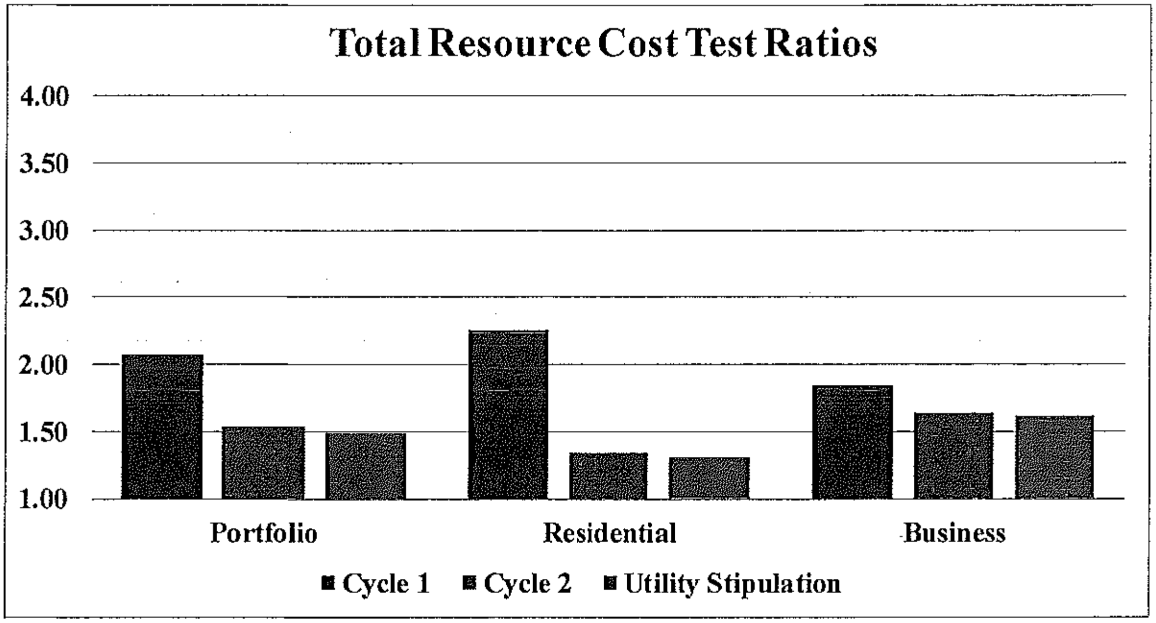
	Benefits and Costs Summary	Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
	Energy Savings Target (GWh)	793	426	584	505	166	224	288	261	360
	Demand Savings Target (MW)	170	114	123	99	36	56	71	78	68
a	Expected Benefits	$ 499	$ 261	$ 350	$ 307	$ 89	$ 119	$ 192	$ 172	$ 231
b	Program Adminstation	$ 79	$ 70	$ 99	$ 45	$ 38	$ 54	$ 34	$ 32	$ 45
c	Customer Incentives	$ 55	$ 56	$ 86	$ 31	$ 14	$ 29	$ 24	$ 42	$ 57
d	Net Participant Cost	$ 106	$ 44	$ 49	$ 60	$ 14	$ 8	$ 46	$ 31	$ 40
e	Participant Bill Reduection	$ 566	$ 355	$ 479	$ 380	$ 145	$ 188	$ 185	$ 215	$ 291
$f = b + c$	Total UCT Cost	$ 134	$ 126	$ 186	$ 76	$ 52	$ 83	$ 58	$ 74	$ 103
$g = b + c + d$	Total TRC Cost	$ 240	$ 170	$ 234	$ 136	$ 66	$ 91	$ 104	$ 105	$ 143
$h = a / f$	UCT	3.72	2.07	1.89	4.04	1.71	1.44	3.31	2.32	2.25
$i = a / g$	TRC	2.08	1.54	1.50	2.26	1.35	1.31	1.85	1.64	1.62
$j = (c+e) / (c+d)$	PCT	3.86	4.11	4.19	4.52	5.67	5.84	2.98	3.52	3.56
$k = a - f$	UCT Net Benefits	$ 365	$ 135	$ 165	$ 231	$ 37	$ 36	$ 134	$ 98	$ 129
l	Throughput Disincentive	$ 95	$ 44	$ 60	$ 61	$ 17	$ 23	$ 34	$ 27	$ 37
m	100% Performance Incentive	$ 19	$ 19	$ 23	$ 12	$ 5	$ 6	$ 7	$ 14	$ 17

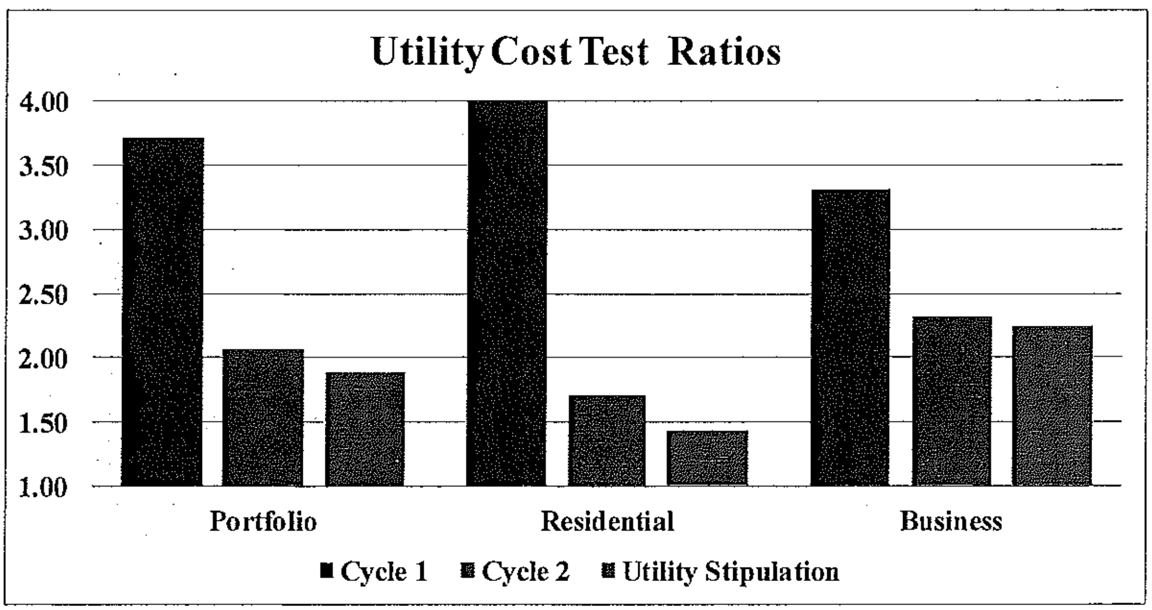
	Customers as a Whole	Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
a	Expected Benefits	$ 499	$ 261	$ 350	$ 307	$ 89	$ 119	$ 192	$ 172	$ 231
b	Program Administation	$ 79	$ 70	$ 99	$ 45	$ 38	$ 54	$ 34	$ 32	$ 45
c	Customer Incentives	$ 55	$ 56	$ 86	$ 31	$ 14	$ 29	$ 24	$ 42	$ 57
m	100% Performance Incentive	$ 19	$ 19	$ 23	$ 12	$ 5	$ 6	$ 7	$ 14	$ 17
$n = b+c+m$	Customers' Costs	$ 153	$ 145	$ 208	$ 88	$ 57	$ 89	$ 65	$ 88	$ 119
$o = a - n$	Customers' Net Benefits	$ 346	$ 116	$ 142	$ 219	$ 32	$ 30	$ 127	$ 84	$ 112
$p = a / n$	Benefits / Costs	3.26	1.80	1.68	3.49	1.56	1.34	2.95	1.96	1.94

	Non-Participanting Customers	Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
a	Expected Benefits	$ 499	$ 261	$ 350	$ 307	$ 89	$ 119	$ 192	$ 172	$ 231
b	Program Administation	$ 79	$ 70	$ 99	$ 45	$ 38	$ 54	$ 34	$ 32	$ 45
c	Customer Incentives	$ 55	$ 56	$ 86	$ 31	$ 14	$ 29	$ 24	$ 42	$ 57
l	Throughput Disincentive	$ 95	$ 44	$ 60	$ 61	$ 17	$ 23	$ 34	$ 27	$ 37
m	100% Performance Incentive	$ 19	$ 19	$ 23	$ 12	$ 5	$ 6	$ 7	$ 14	$ 17
$q = b+c+l+m$	Customers' Costs	$ 248	$ 189	$ 269	$ 149	$ 74	$ 112	$ 99	$ 115	$ 157
$r = a - q$	Customers' Net Benefits	$ 251	$ 72	$ 82	$ 158	$ 15	$ 7	$ 93	$ 57	$ 75
$s = a / q$	Benefits / Costs	2.01	1.38	1.31	2.07	1.20	1.06	1.93	1.50	1.48

	Participating Customers	Portfolio			Residential			Business		
		Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation	Cycle 1	Cycle 2	Utility Stipulation
d	Net Participant Cost	$ 106	$ 44	$ 49	$ 60	$ 14	$ 8	$ 46	$ 31	$ 40
c	Customer Incentives	$ 55	$ 56	$ 86	$ 31	$ 14	$ 29	$ 24	$ 42	$ 57
e	Participant Bill Reductions	$ 566	$ 355	$ 479	$ 380	$ 145	$ 188	$ 185	$ 215	$ 291
$t = c + d$	Customers' Costs	$ 161	$ 100	$ 135	$ 91	$ 28	$ 37	$ 70	$ 73	$ 98
$u = c + e$	Customers' Benefits	$ 621	$ 411	$ 565	$ 411	$ 159	$ 217	$ 209	$ 257	$ 348
$v = u / t$	Benefits / Costs	3.86	4.11	4.19	4.52	5.67	5.84	2.98	3.52	3.56

* Cycle 1
** Cycle 2
*** Utility Stipulation


Total Resource Cost Test Ratios
4.00
3.50
3.00
2.50
2.00
1.50
1.00
Portfolio
Residential
Business
Cycle 1
Cycle 2
Utility Stipulation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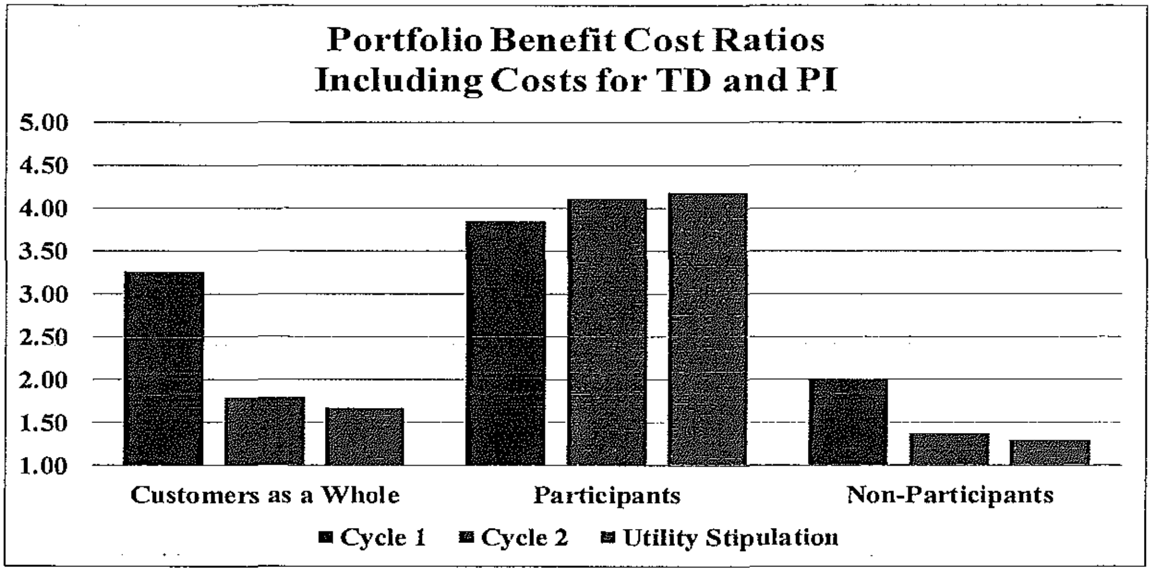
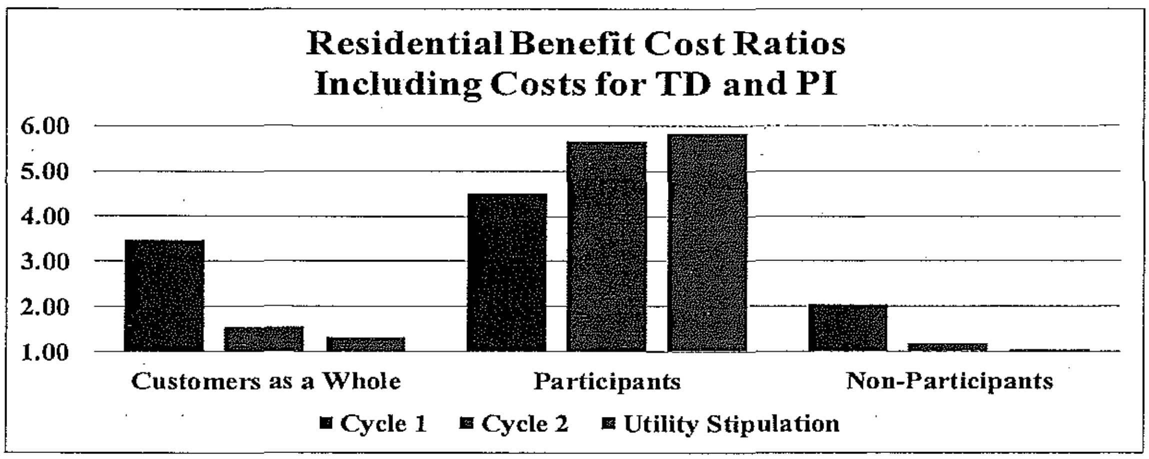
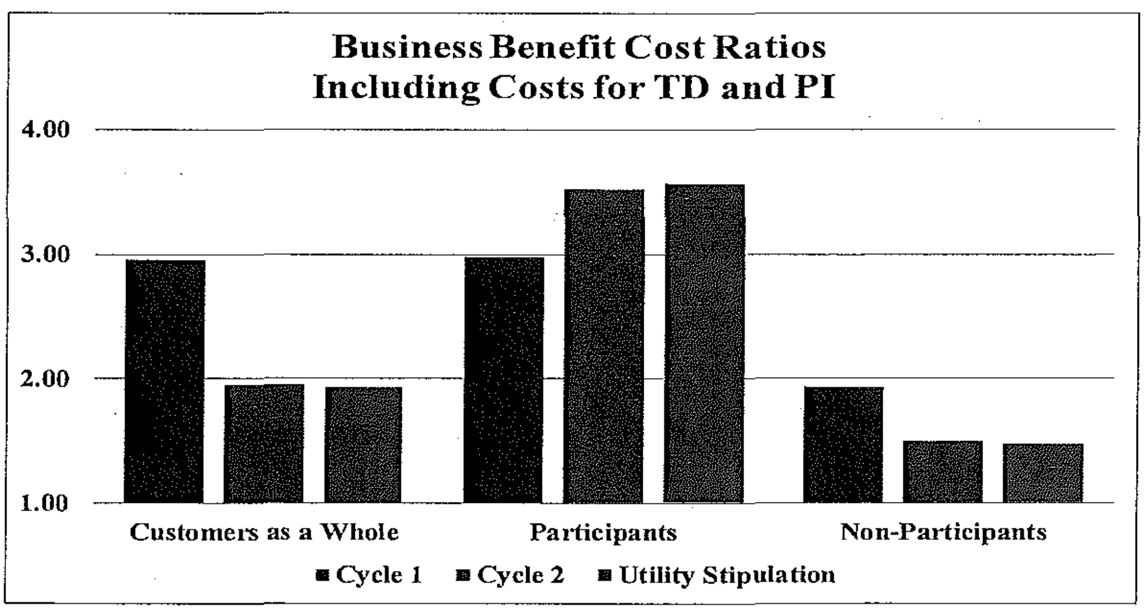
4.00
3.50
3.00
2.50
2.00
1.50
1.00
Portfolio
Residential
Business
Cycle 1
Cycle 2
Utility Stipulation


Portfolio Benefit Cost Ratios
Including Costs for TD and PI
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
Customers as a Whole
Participants
Non-Participants
Cycle 1
Cycle 2
Utility Stipulation


Residential Benefit Cost Ratios
Including Costs for TD and PI
6.00
5.00
4.00
3.00
2.00
1.00
Customers as a Whole
Participants
Non-Participants
Cycle 1
Cycle 2
Utility Stipulation


Business Benefit Cost Ratios
Including Costs for TD and PI
4.00
3.00
2.00
1.00
Customers as a Whole
Participants
Non-Participants
Cycle 1
Cycle 2
Utility Stipulation