

Direct Testimony and Schedules  
Shawn L. Gillespie

Before the Minnesota Public Utilities Commission  
State of Minnesota

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to  
Increase Rates for Natural Gas Service in Minnesota

Docket No. G007,011/GR-10-977

Exhibit \_\_\_\_\_

**Purchased Gas Adjustment Consolidation**

November 30, 2010

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS .....1

II. FILING REQUIREMENTS .....3

III. DESCRIPTION OF CURRENT PGA SYSTEM .....5

IV. PGA CONSOLIDATION PROPOSAL .....12

V. RATE IMPACTS OF PROPOSAL .....20

VI. CONCLUSION.....30

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A. My name is Shawn L. Gillespie. My business address is 1412 Howard Street, Omaha,  
4 Nebraska 68102.

5  
6 Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

7 A. I am employed by Integrys Business Support, LLC as Manager of Gas Supply for  
8 Minnesota Energy Resources Corporation (“MERC” or the “Company”).

9  
10 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

11 A. I have a Bachelor of Science (B.S.) degree in Accounting and a Masters of Business  
12 Administration (M.B.A.) from Bellevue University, in Bellevue, Nebraska. I have been  
13 employed in the natural gas industry since April 1994 in various capacities. I was  
14 employed by Aquila, Inc. from April 1994 through June 2006. At Aquila I was employed  
15 in the following areas: Purchased Gas Adjustment (“PGA”) Analyst, Gas Dispatcher,  
16 Transportation and Exchange (“T&E”) Specialist, Buyer, and Planning. As a PGA  
17 Analyst I made the monthly PGA filings as well as any other required PGA related  
18 regulatory filings in the State of Kansas. As a Gas Dispatcher, I forecasted and  
19 nominated natural gas on various natural gas pipelines. As a T&E Specialist, my role  
20 was to optimize the contracted storage and transportation capacity. As a Buyer, I was  
21 responsible for purchasing the required natural gas supply for Aquila’s regulated  
22 customers in Colorado, Kansas, Missouri and Nebraska. In the Planning role, I was  
23 responsible for calculating the theoretical peak day, insuring adequate levels of pipeline

1 capacity for peak day needs, negotiating transportation and storage contracts with  
2 appropriate pipelines, developing the winter hedging plan, executing the hedging plan by  
3 purchasing the hedged gas, and handling all FERC and state regulatory issues related to  
4 the gas supply function in the States of Colorado, Kansas, Missouri and Nebraska. When  
5 MERC acquired the natural gas operations of Aquila in Minnesota in July 2006, I became  
6 Manager of Gas Supply for MERC. My responsibilities include insuring MERC has  
7 adequate levels of pipeline capacity to meet the theoretical peak day, negotiating all  
8 transportation and storage contracts with appropriate pipelines, developing the winter  
9 hedging plan, executing the hedging plan by purchasing the hedged gas, monitoring  
10 FERC activities on all interstate pipelines that affect MERC customers, and assisting with  
11 filings submitted to the Minnesota Public Utilities Commission (“Commission”). I also  
12 am responsible for managing the gas supply office located in Omaha, Nebraska.

13  
14 Q. FOR WHOM ARE YOU PROVIDING TESTIMONY?

15 A. I am providing testimony on behalf of MERC.

16  
17 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

18 A. My testimony addresses the Company’s proposal to consolidate its PGA. I recommend  
19 that the Commission consolidate the Company’s PGA from four separate PGAs to two  
20 PGAs as discussed below.

21

1 **II. FILING REQUIREMENTS**

2 Q. IN THE COMMISSION’S APRIL 16, 2010 ORDER AUTHORIZING WITHDRAWAL  
3 WITHOUT PREJUDICE IN DOCKET NO. G-007,011/M-08-271, THE COMMISSION  
4 REQUIRED THAT MERC INCLUDE THE FOLLOWING INFORMATION IN ITS  
5 NEXT RATE CASE IF THAT RATE CASE INCLUDES A REQUEST TO  
6 CONSOLIDATE ITS PGAS:

- 7 A. FULLY DESCRIBE THE PHYSICAL FLOW AND EXTENT OF  
8 INTEGRATION OF THE PIPELINE SYSTEM;  
9  
10 B. ADDRESS WHETHER THERE WILL BE INTER-PIPELINE OR  
11 INTER-REGIONAL SUBSIDY AS A RESULT OF CONSOLIDATION;  
12 AND  
13  
14 C. ADDRESS WHETHER ANY CHANGES IN THE CONDITIONS OF  
15 SERVICE ARE SUFFICIENTLY GRADUAL TO AVOID DRASTIC  
16 RATE CHANGES (RATE SHOCK) TO CUSTOMERS.  
17

18 DOES YOUR TESTIMONY ADDRESS THE COMMISSION’S REQUIREMENTS?

19 A. Yes, it does.  
20

21 Q. THE COMMISSION ALSO REQUIRED THAT AT LEAST 60 DAYS PRIOR TO  
22 FILING A REQUEST TO CONSOLIDATE ITS PGAS, MERC SHALL MEET WITH  
23 THE OES, COMMISSION STAFF, AND ANY OTHER INTERESTED PARTIES TO  
24 DISCUSS THE PROPOSAL AND CLARIFY ANY CONCERNS RAISED BY OTHER  
25 PARTIES. HAS MERC COMPLIED WITH THIS REQUIREMENT?

26 A. Yes, MERC met with representatives from the Office of Energy Security (“OES”) and  
27 Commission Staff on August 18, 2010 to discuss the Company’s proposal to consolidate  
28 its PGAs. MERC also invited the Office of the Attorney General – Residential Utilities  
29 Division, the intervenors in the Company’s last rate case in Docket No. G007,011/GR-

1 08-835, and Energy Cents Coalition to the meeting, although no representatives from  
2 these entities attended the meeting.

3  
4 Q. AS REQUIRED BY THE COMMISSION'S ORDER, DO YOUR TESTIMONY AND  
5 EXHIBITS INCLUDE ALL THE NECESSARY WORKPAPERS AND  
6 DOCUMENTATION TO SUPPORT ANY CLAIMS MADE AS TO WHY IT IS IN  
7 THE RATEPAYER'S INTEREST TO CONSOLIDATE THE PGAS?

8 A. Yes, all necessary workpapers and documentation are included within my testimony and  
9 exhibits as well as the following documents: the base cost of gas filing submitted in  
10 Docket No. G007,011/MR-10-978, the 2010/2011 Demand Entitlement filings submitted  
11 in Docket Nos. G007/M-10-1166, G011/M-10-1167, G011/M-10-1168, and G011/M-10-  
12 1169, the Direct Testimony and Exhibits of Mr. Harry Johns, which present the  
13 Company's 2011 test year sales forecast, the Direct Testimony and Exhibits of Mr. Seth  
14 DeMerritt, which calculate the division of the forecasted sales MERC-NMU sales  
15 between those customers who are served by the NNG pipeline and those who are not, and  
16 the Direct Testimony and Exhibits of Mr. Greg Walters, which evaluate the rate impacts  
17 of our PGA consolidation proposal in conjunction with the Company's proposal to  
18 consolidate the distribution rate areas for MERC-PNG and MERC-NMU.

19

1 **III. DESCRIPTION OF CURRENT PGA SYSTEM**

2 Q. PLEASE PROVIDE AN OVERVIEW OF MERC’S CURRENT PGA SYSTEM.

3 A. MERC’s customers are currently served either by the MERC-PNG operating division or  
4 the MERC-NMU operating division of the Company. Within the PNG operating  
5 division, natural gas is supplied to customers from three (3) pipelines: Northern Natural  
6 Gas (“NNG”), Great Lakes Gas Transmission (“GLGT”), and Viking Gas Transmission  
7 (“VGT”). For the NMU operating division, natural gas is supplied to customers from  
8 four (4) pipelines: NNG, GLGT, VGT, and Centra. A copy of MERC’s system map  
9 showing the locations of the PNG and NMU service areas as well as the pipelines serving  
10 each can be found in Mr. Charles Cloninger’s testimony and exhibits as Exhibit \_\_\_\_\_  
11 (CAC-1).

12  
13 Each operating division currently has a different PGA system in place. MERC-PNG has  
14 three PGAs that are calculated separately by pipeline (NNG, GLGT, and VGT). MERC-  
15 NMU, on the other hand, currently has a single PGA that combines the gas purchased on  
16 the four different pipelines (NNG, GLGT, VGT, and Centra). Based on the 2011 sales  
17 forecast presented by MERC witness Mr. Harry Johns in this proceeding, Figure 1  
18 provides an overview of MERC’s current PGA systems and outlines the sales in millions  
19 of therms through each pipeline system.

20

1  
2

**Figure 1: MERC 2011 Forecasted Sales Volumes by Current PGA Systems**

MERC - Current PGA Systems						
PNG		Division			NMU	
NNG	GLGT	PGA System		NMU		
		VGT	Pipeline			
NNG	GLGT	VGT	NNG	GLGT	VGT	Centra
224.0*	9.2*	7.8*	26.9*	15.8*	12.1*	10.2*

3

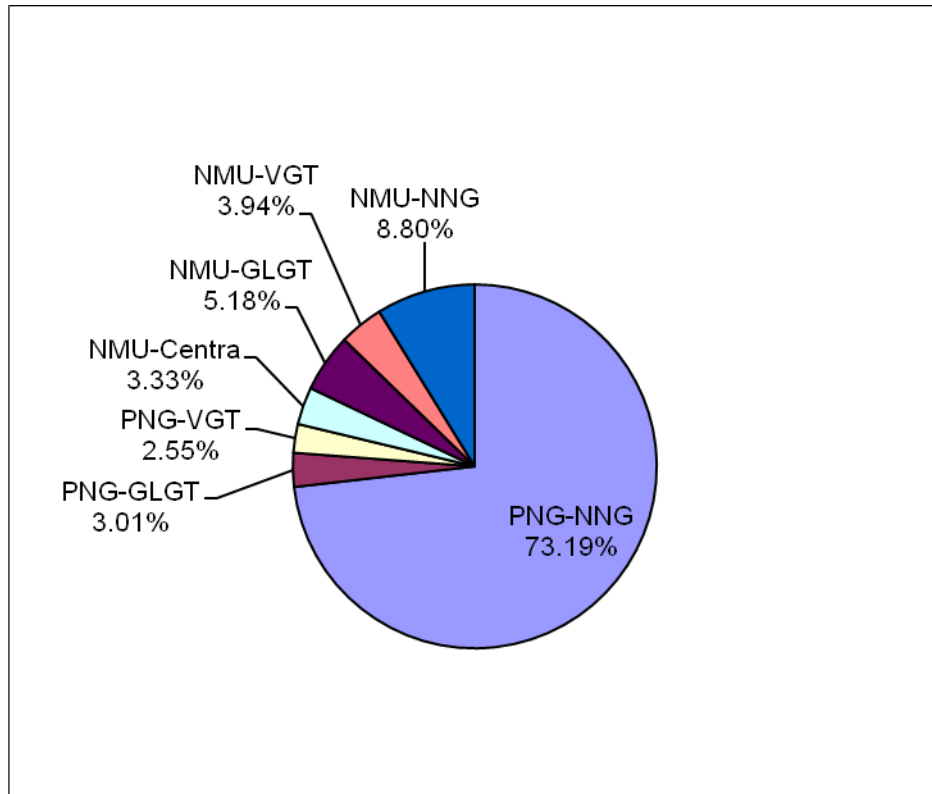
\* Annual Sales in Million therms including lost and unaccounted for and company use gas.

4  
5

Figure 2 below outlines the forecasted annual sales volumes by percentage of total MERC sales.

6

**Figure 2: MERC 2011 Forecasted Sales Volumes by Current PGA Systems**



7  
8  
9

1 As shown in Figures 1 and 2, the majority of sales on MERC's system are to MERC-  
2 PNG customers served off the NNG pipeline (73.19%), with the remaining sales divided  
3 among the operating divisions and pipelines. The NNG pipeline is also the largest source  
4 of gas for MERC-NMU customers. In total, the NNG pipeline provides gas to 82% of  
5 MERC's customers.

6  
7 Q. HOW DOES THE EXISTING PGA SYSTEM AFFECT COSTS FOR PNG AND NMU  
8 CUSTOMERS SERVED BY THE SAME PIPELINE?

9 A. As a consequence of the different PGA structures for MERC-PNG and MERC-NMU,  
10 there are currently customers served off of the same pipeline who are charged different  
11 PGA rates. For example, MERC's customers served off of the NNG, GLGT, and VGT  
12 pipelines are charged different rates based solely on whether they are located within the  
13 PNG or NMU service area even though they are consuming gas from the same pipeline  
14 and costs by pipeline do not differ based on whether service is provided by PNG or  
15 NMU.

16  
17 For example, as shown in the Base Cost of Gas filing in Docket No. G007,011/GR-10-  
18 978, a NMU customer in Moose Lake pays \$0.70263 per therm of gas, while a PNG  
19 customer in Sturgeon Lake, just 5 miles away on the NNG pipeline, pays \$0.74168 per  
20 therm of gas even though the cost of gas charged by the pipeline does not vary.

21 Similarly, a customer in Thief River Falls (located in the NMU service area) pays  
22 \$0.70263 per therm of gas, while a customer in Bemidji (located in the PNG service area)  
23 pays \$0.62818 per therm of gas even though both customers consume gas from the

1 GLGT pipeline at the same cost. The same disparity occurs on the VGT pipeline as well,  
2 as a PNG customer in Frazee pays \$0.65637 per therm of gas, while a NMU customer in  
3 Wadena pays \$0.70263 per therm.<sup>1</sup>

4  
5 Q. HOW DO THE PER THERM DIFFERENCES DISCUSSED ABOVE TRANSLATE  
6 INTO DIFFERENCES IN ANNUAL GAS COSTS FOR RESIDENTIAL CUSTOMERS  
7 SERVED BY THE SAME PIPELINE IN THE PNG AND NMU OPERATING  
8 DIVISIONS?

9 A. Even though the cost of gas charged by the pipeline is the same, Table 1 below outlines  
10 the different annual gas costs paid by PNG and NMU residential customers who are  
11 served by the same pipeline.

12 **Table 1: Annual Residential Gas Costs Based on Average Usage\***

Pipeline	Annual Gas Cost - PNG	Annual Gas Cost - NMU
NNG	\$657.13	\$622.53
GLGT	\$556.57	\$622.53
VGT	\$581.54	\$622.53

13 \*Based on 886 therms per year for the average residential customer on the MERC system.  
14 See Exhibit \_\_\_\_\_ (SLG-2).  
15

16 Table 1 shows that there is a wide difference in the amount of gas costs paid by  
17 customers served by the same pipeline. These differences are not based on any actual

---

<sup>1</sup> MERC has used the rates filed in the base cost of gas filing in Docket No. G007,011/MR-10-978 for the purpose of this comparison. MERC has proposed changes in its demand entitlement filings filed in Docket Nos. G007/M-10-1166, G011/M-10-1167, G011/M-10-1168, and G011/M-10-1169 that are not reflected in this comparison. The proposed changes are discussed in more detail below.

1 differences in gas cost, but instead are based on whether the customer is located within  
2 the PNG or NMU service area.

3  
4 Q. PLEASE DISCUSS THE PHYSICAL FLOW AND INTEGRATION OF THE  
5 PIPELINE SYSTEM SERVING MERC'S CUSTOMERS.

6 A. Supply for the GLGT and VGT pipelines is sourced at Emerson, and supply for the  
7 Centra pipeline is sourced at Spruce, whereas supply for NNG is sourced at multiple  
8 receipt points. The supply for Emerson and Spruce is sourced from the Alberta Energy  
9 Company ("AECO") supply hub located in Alberta, Canada. This gas is traded at the  
10 AECO Hub, then transported via TransCanada Pipeline ("TCPL") to either Emerson or  
11 Spruce. The cost of the gas is similarly priced at both points, and typically when MERC  
12 purchases supply for GLGT, VGT and Centra, MERC requests the flexibility to move gas  
13 from either receipt point into any of the three pipelines. This flexibility gives MERC the  
14 ability to better balance the pipelines and enhances reliability by allowing the movement  
15 of gas where it is needed.

16  
17 As mentioned above, supply on the NNG pipeline can be sourced at multiple receipt  
18 points. Figure 3 outlines the various NNG receipt points, supply region and index pricing  
19 mechanisms.

20

1

**Figure 3: NNG Receipt Points**

NBPL/NNG Aberdeen	South Dakota	AECO	NNG Ventura
NBPL/NNG Marshall	Minnesota	AECO	NNG Ventura
NBPL/NNG Ventura	Iowa	AECO/Rockies	CIG/NNG Ventura
NBPL/NNG Welcome	Minnesota	AECO	NNG Ventura
GLGT/NNG Grand Rapids	Minnesota	AECO	NYMEX
GLGT/NNG Carlton	Minnesota	AECO	NYMEX
TBPL/NNG Beatrice	Nebraska	Rockies	NGPL MidContinent
NNG Field/Demarcation	Kansas	MidContinent	NNG Demarc

2

3

4

5

6

7

8

9

As Figure 3 indicates, the gas is sourced from multiple supply regions using different index pricing mechanisms. MERC nominates to a single zone on NNG, so gas from any of these receipt point(s) can be used to supply any MERC customers on NNG, whether they are located in the PNG or NMU service area. In other words, MERC does not differentiate between gas supply for PNG or NMU when the supply is purchased and nominated on the NNG pipeline.

10

11

12

13

14

15

In addition to the common supply point for the GLGT, VGT, and Centra pipelines, there are various MERC communities that are or can be served by more than one pipeline. In particular, Thief River Falls is supplied by both the GLGT and VGT pipelines, and Windom is supplied by both NNG and Northern Border Pipeline (“NBPL”). Grand Rapids and Cloquet are currently supplied by GLGT but can be supplied by NNG as well.

1           Additionally, there are three points at which the pipelines serving MERC communities  
2           interconnect. The NNG pipeline interconnects with the VGT pipeline at Chisago, and the  
3           NNG pipeline interconnects with the GLGT pipeline at Carlton and Grand Rapids.

4           Although gas cannot physically flow from NNG to VGT or GLGT due to differences in  
5           pressure, MERC could bring gas from the NNG pipeline to the GLGT and VGT pipelines  
6           through displacement. As an example, MERC could purchase supply on the NNG  
7           pipeline at NNG Ventura and transport the supply on NNG to Chisago, the interconnect  
8           with VGT, or to Carlton or Grand Rapids, the interconnects with GLGT. Gas could then  
9           be swapped from one pipeline to another through displacement. Since gas cannot  
10          physically flow from NNG to GLGT or VGT, this transaction requires an equal amount  
11          of supply on the other pipeline to swap the gas. Such a swap would be performed to take  
12          advantage of lower pricing on one pipeline versus the other, but typically such a  
13          transaction would not be economical compared to purchasing the supply directly on  
14          GLGT or VGT. Moreover, MERC cannot generally rely on the ability to swap gas  
15          because an equal amount of supply must be available on each pipeline.

16  
17          As discussed above, the GLGT, VGT, and Centra pipelines are physically connected at  
18          their source, and gas supply can be redirected from one pipeline to another at the source.  
19          Several communities on MERC's system also are able to take supply from more than one  
20          pipeline.

21

**IV. PGA CONSOLIDATION PROPOSAL**

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12

Q. PLEASE DISCUSS MERC’S PROPOSAL TO CONSOLIDATE ITS PGAS.

A. MERC proposes to move from a system of four PGAs to a system of two PGAs by consolidating the PGAs for GLGT, VGT, and Centra across the PNG and NMU operating divisions (“MERC-Consolidated”) and establishing a single PGA for the NNG pipeline supplying both PNG and NMU (“MERC-NNG”). Figures 4 and 5 provide an overview of MERC’s proposed PGA system and provide sales by PGA both in terms of therms and in percentage of total MERC sales.

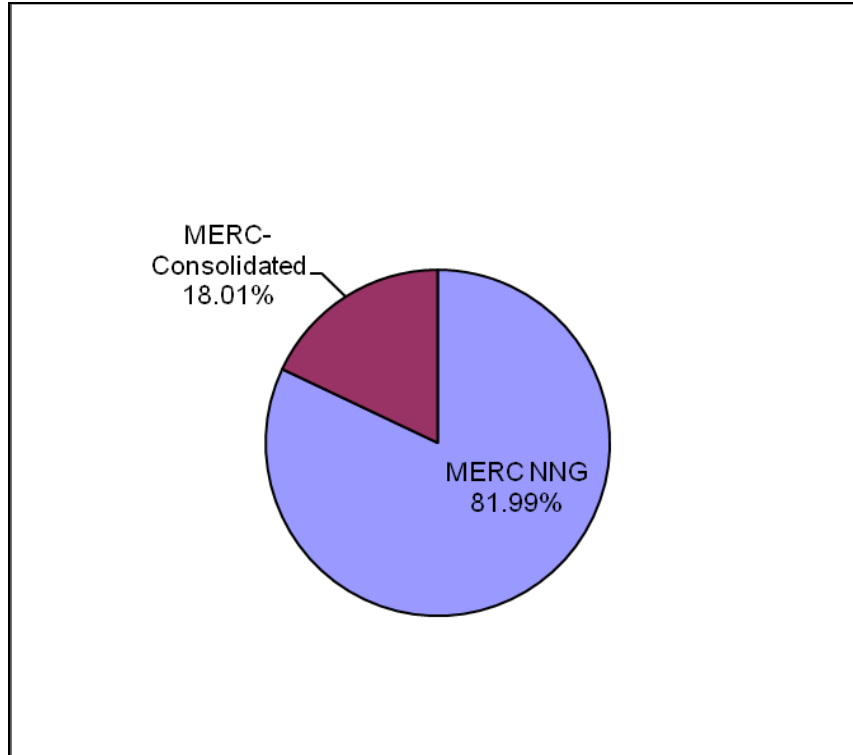
**Figure 4: MERC 2011 Forecasted Sales Volumes by Proposed PGA Systems**

<b>MERC - Proposed PGA Systems</b>				
<b>PGA System</b>				
NNG			Consolidated	
<b>Pipeline</b>				
NNG		GLGT	VGT	Centra
250.9*		25.0*	19.9*	10.2*

\* Annual Sales in Million therms including lost and unaccounted for and company use gas.

1

**Figure 5: MERC 2011 Forecasted Sales Volumes by Proposed PGA Systems**



2

3

4 Q. PLEASE EXPLAIN WHY MERC HAS PROPOSED A SINGLE PGA FOR GLGT,  
5 VGT, AND CENTRA.

6 A. MERC has proposed a consolidated PGA for GLGT, VGT, and Centra because the gas  
7 supplied off of those pipelines comes from the same source and the cost for gas on those  
8 pipelines is very similar. In particular, the cost of gas for supply at Emerson and Spruce  
9 is typically the same since the two receipt points are located in Manitoba Province in  
10 Canada, although there is a difference in the cost of the transportation on each of the  
11 pipelines. Figure 6 indicates the cost of transportation per Dth by pipeline and the cost of  
12 transportation on these pipelines combined. As shown in Figure 6, the cost of  
13 transportation is very similar on the GLGT and VGT pipelines and is higher on the  
14 Centra pipeline. Due to the small amount of capacity contracted on Centra, however, the

1 combined cost of transportation is only approximately \$0.50 higher per Dth than the cost  
 2 on GLGT and VGT.

Figure 6:

GLGT/VGT/Centra Transportation Reservation Costs

Pipeline	Contracted Winter Capacity Dth	Maximum Tariff Rate Dth	Maximum Tariff Cost Total
GLGT	27,946	\$ 3.4580	\$ 96,637.27
VGT	15,591	\$ 3.4671	\$ 54,055.56
Centra *	9,858	\$ 6.2212	\$ 61,328.59
Total	53,395	\$ 3.9708	\$ 212,021.41

\* A Canadian to US \$ Conversion was used.

3

4 Q. ARE THERE ANY OTHER DIFFERENCES IN THE COST OF GAS SUPPLIED OFF  
 5 OF THE GLGT AND VGT PIPELINES?

6 A. Currently, PNG-VGT and NMU customers are allocated costs from gas supplied on the  
 7 NNG pipeline with a delivery point of Chisago. This capacity is allocated to PNG-VGT  
 8 and NMU customers because the capacity is necessary to meet peak day demand for  
 9 customers supplied off of VGT. Therefore historically costs on VGT have been higher  
 10 than costs on GLGT. In the 2010-2011 Demand Entitlement filing, none of the NNG  
 11 pipeline capacity was allocated to PNG-VGT. The NNG capacity was allocated to PNG-  
 12 NNG and NMU-NNG customers. In lieu of using NNG capacity to meet peak day needs  
 13 on PNG-VGT and NMU-VGT, MERC purchased a delivered gas daily call option at  
 14 Wadena. The demand cost for PNG-VGT decreased from \$0.10565 per therm to  
 15 \$0.09343 per therm which makes the demand cost very similar to what was calculated

1 for PNG-GLGT at \$0.08465 per therm. See Tables 4 and 7 below, which list the per  
2 therm demand costs based on 2011 forecasted sales.

3 Q. PLEASE EXPLAIN WHY MERC HAS PROPOSED A SINGLE PGA FOR NNG.

4 A. The gas supplied through the NNG pipeline is sourced at different points from the gas  
5 supplied through the GLGT, VGT, and Centra pipelines, and the costs on the NNG  
6 pipeline are different from those on the other pipelines. MERC therefore has proposed a  
7 separate PGA solely for gas supplied off of the NNG pipeline.

8

9 Q. WHAT ARE THE BENEFITS OF MERC'S PROPOSAL?

10 A. MERC's proposal will minimize subsidization among ratepayers, result in consistent cost  
11 of gas for the pipelines serving both PNG and NMU communities, eliminate cost  
12 allocation, streamline MERC's hedging practices, and reduce the administrative burden  
13 for the OES, the Commission, and MERC.

14

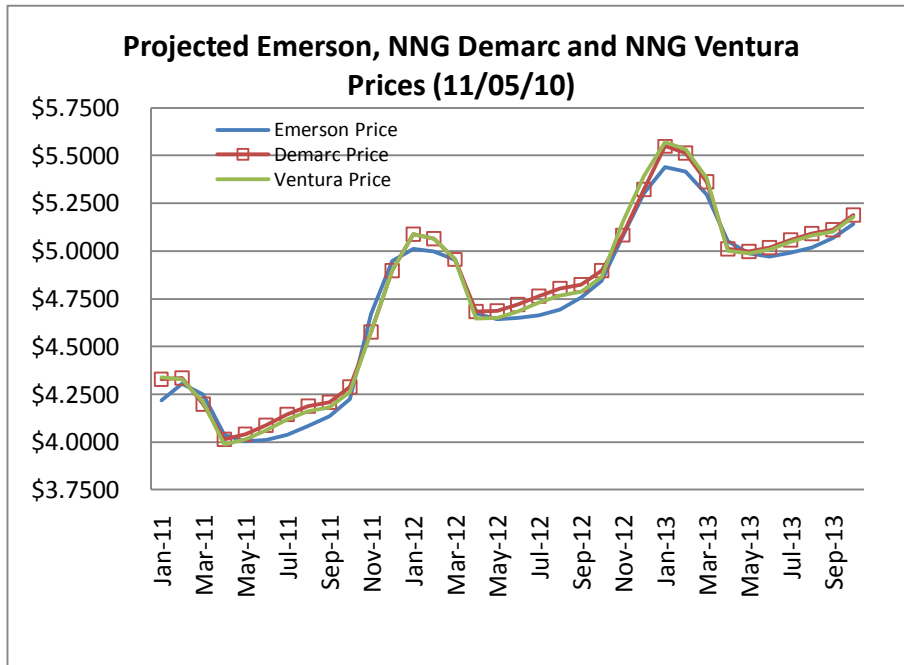
15 Q. HOW DOES MERC'S PROPOSAL MINIMIZE SUBSIDIZATION AMONG  
16 RATEPAYERS?

17 A. Gas costs on the NNG pipeline are currently higher than those on the GLGT, VGT, and  
18 Centra pipelines. This is demonstrated in Figure 7, which projects gas costs between  
19 Emerson, NNG Demarc and NNG Ventura.

20

1

Figure 7



2

3

4

5

6

7

8

9

10

11

Under MERC’s current PGA system, MERC-NMU has a consolidated PGA that combines the cost of gas on NNG, GLGT, VGT, and Centra. Since gas costs are higher on the NNG pipeline, MERC-NMU customers who obtain service off of the GLGT, VGT, and Centra pipelines are currently subsidizing the cost of gas for MERC-NMU’s customers served off of NNG. As shown in Figure 8, these customers make up approximately 41 percent of MERC-NMU’s sales volumes and 8.80 percent of total MERC sales as shown in Figures 1 and 2.

1 **Figure 8: MERC 2011 Sales Forecast for NMU by Pipeline**

<b>Current PGA Systems</b>	<b>Therms*</b>	<b>% of NMU System</b>
<b>NMU-NNG</b>	26,941,390	41.42%
<b>NMU-GLGT</b>	15,827,579	24.33%
<b>NMU-VGT</b>	12,070,814	18.56%
<b>NMU-Centra</b>	10,205,038	15.69%
<b>NMU Total</b>	65,044,820	100.00%

2 \* Annual Sales including lost and unaccounted for and company use gas.

3  
4 Creating a separate PGA solely for customers (both PNG and NMU) supplied off the  
5 NNG pipeline will eliminate subsidization of MERC-NMU's customers obtaining service  
6 off of the NNG pipeline by MERC-NMU customers obtaining service off of the other  
7 pipelines.

8  
9 Q. HOW DOES MERC'S PROPOSAL RESULT IN CONSISTENT COSTS OF GAS FOR  
10 CUSTOMERS?

11 A. As discussed above, MERC's current PGA system results in inconsistent PGA rates for  
12 customers supplied by the same pipeline in the PNG and NMU service areas even though  
13 gas costs do not vary on the same pipeline. Under MERC's proposal, PGA rates will be  
14 consistent for all customers supplied off of the same pipeline, and PGA rates will not  
15 differ based solely on whether a customer is located in the PNG or NMU service area.

16  
17 Q. PLEASE DISCUSS THE ELIMINATION OF ALLOCATIONS UNDER MERC'S  
18 PROPOSAL.

1 A. Given that both PNG and NMU customers are served by the same pipelines but subject to  
2 different PGA rates, the Company currently must allocate demand and commodity costs  
3 by pipeline between PNG and NMU. For example, the Company must allocate NNG  
4 demand and commodity costs between the PNG-NNG and NMU PGAs, GLGT demand  
5 and commodity costs between the PNG-GLGT and NMU PGAs, and VGT demand and  
6 commodity costs between the PNG-VGT and NMU PGAs. Under MERC's PGA  
7 proposal in this proceeding, all customers served by the same pipeline would be charged  
8 the same PGA rate, and no allocation of demand and commodity costs would be  
9 necessary.

10

11 Q. HOW WILL THE PROPOSED PGA CONSOLIDATION IMPACT MERC'S  
12 HEDGING PRACTICES?

13 A. MERC currently prepares seven distinct hedging plans (PNG-NNG, PNG-GLGT, PNG-  
14 VGT, NMU-NNG, NMU-GLGT, NMU-VGT and NMU-Centra), and hedging costs are  
15 allocated across the four PGA systems MERC has in place today based upon the plans.  
16 Following the proposed PGA consolidation, MERC will be able to prepare only two  
17 hedging plans, and there will be no need to allocate hedging costs. For the consolidated  
18 GLGT, VGT and Centra PGA, MERC could choose to hedge all volumes on one of the  
19 pipelines and not have to hedge on the other two pipelines. This practice would reduce  
20 the number of hedges that have to be made and would simplify the hedging process. The  
21 same is true for hedging on NNG. Instead of hedging separately for PNG-NNG and  
22 NMU-NNG, MERC will be able to purchase hedges based solely on the combined  
23 hedging requirement.

1  
2  
3  
4  
5  
6  
7  
8  
9  
10

Q. WHEN DO YOU PROPOSE THAT CONSOLIDATION OF THE PGAS TAKE EFFECT?

A. MERC proposes that consolidation of the PGA rates be effective on July 1<sup>st</sup> after final rates go into effect and that consolidation of the true-up factors be effective with the first Annual Automatic Adjustment and True-up filings made on September 1<sup>st</sup> after final rates go into effect. This timeline would streamline implementation of the changes, as PGA rates would go into effect with the start of the new annual automatic adjustment year on July 1<sup>st</sup>, and the true-up factors would go into effect at the beginning of the true-up cycle.

**V. RATE IMPACTS OF PROPOSAL**

Q. PLEASE DISCUSS THE IMPACTS OF YOUR PROPOSAL ON CUSTOMERS' COST OF GAS.

A. MERC's proposal will result in a small impact on customers' cost of gas, with many customers seeing a decrease in PGA rates. Based upon an analysis of projected PGA rates for 2011 under the current PGA system compared to MERC's proposed PGA system, the following impacts are expected for the commodity cost of gas (Table 2), volumetric cost of gas (Table 3), demand cost of gas (Table 4), and total cost of gas (Table 5). Please see the base cost of gas filing submitted in Docket No. G007,011/MR-10-978 for details regarding the projected rates.

**Table 2: Commodity Cost of Gas (Gas Cost Per Therm)**

	<b>Current PGA System</b>	<b>Proposed PGA System</b>	<b>Increase/(Decrease)</b>
<b>PNG-NNG</b>	\$0.56721	\$0.56918	\$0.00197
<b>PNG-GLGT</b>	\$0.55065	\$0.54551	(\$0.00514)
<b>PNG-VGT</b>	\$0.54921	\$0.54551	(\$0.0037)
<b>NMU-NNG</b>	\$0.56093	\$0.56918	\$0.00825
<b>NMU-GLGT</b>	\$0.56093	\$0.54551	(\$0.01542)
<b>NMU-VGT</b>	\$0.56093	\$0.54551	(\$0.01542)
<b>NMU-Centra</b>	\$0.56093	\$0.54551	(\$0.01542)

See Exhibit \_\_\_\_\_ (SLG-1) Page 1 of 6 (MERC Proposed Consolidated Commodity Cost Comparison) for a graphical representation.

1

**Table 3: Volumetric Cost of Gas (Gas Cost Per Therm)**

	<b>Current PGA System</b>	<b>Proposed PGA System</b>	<b>Increase/(Decrease)</b>
<b>PNG-NNG</b>	\$0.00554	\$0.00565	\$0.00011
<b>PNG-GLGT</b>	\$0.00052	\$0.00096	\$0.00044
<b>PNG-VGT</b>	\$0.00151	\$0.00096	(\$0.00055)
<b>NMU-NNG</b>	\$0.00329	\$0.00565	\$0.00236
<b>NMU-GLGT</b>	\$0.00329	\$0.00096	(\$0.00233)
<b>NMU-VGT</b>	\$0.00329	\$0.00096	(\$0.00233)
<b>NMU-Centra</b>	\$0.00329	\$0.00096	(\$0.00233)

2

3

See Exhibit \_\_\_\_\_ (SLG-1) Page 2 of 6 (MERC Proposed Consolidated Volumetric Cost

4

Comparison) for a graphical representation.

5

**Table 4: Demand Cost of Gas (Gas Cost Per Therm)**

	<b>Current PGA System</b>	<b>Proposed PGA System</b>	<b>Increase/(Decrease)</b>
<b>PNG-NNG</b>	\$0.16893	\$0.16894	\$0.00001
<b>PNG-GLGT</b>	\$0.07701	\$0.10639	\$0.02938
<b>PNG-VGT</b>	\$0.10565	\$0.10639	\$0.00074
<b>NMU-NNG</b>	\$0.13841	\$0.16894	\$0.03053
<b>NMU-GLGT</b>	\$0.13841	\$0.10639	(\$0.03202)
<b>NMU-VGT</b>	\$0.13841	\$0.10639	(\$0.03202)
<b>NMU-Centra</b>	\$0.13841	\$0.10639	(\$0.03202)

6

7

See Exhibit \_\_\_\_\_ (SLG-1) Page 3 of 6 (MERC Proposed Consolidated Demand Cost

8

Comparison) for a graphical representation.

1

**Table 5: Total Cost of Gas (Gas Cost Per Therm)**

	<b>Current PGA System</b>	<b>Proposed PGA System</b>	<b>Increase/(Decrease)</b>
<b>PNG-NNG</b>	\$0.74168	\$0.74377	\$0.00209
<b>PNG-GLGT</b>	\$0.62818	\$0.65286	\$0.02468
<b>PNG-VGT</b>	\$0.65637	\$0.65286	(\$0.00351)
<b>NMU-NNG</b>	\$0.70263	\$0.74377	\$0.04114
<b>NMU-GLGT</b>	\$0.70263	\$0.65286	(\$0.04977)
<b>NMU-VGT</b>	\$0.70263	\$0.65286	(\$0.04977)
<b>NMU-Centra</b>	\$0.70263	\$0.65286	(\$0.04977)

2

3

See Exhibit \_\_\_\_\_ (SLG-1) Page 4 of 6 (MERC Proposed Consolidated PGA

4

Comparison) for a graphical representation.

5

6

**Q. WHAT ARE THE BILL IMPACTS ASSOCIATED WITH YOUR PROPOSAL FOR RESIDENTIAL CUSTOMERS?**

7

8

**A.** Table 6 calculates the monthly, annual, and monthly average bill impacts due to PGA consolidation. As a result, Table 6 shows only the estimated difference in the gas cost

9

10

portion of a customer’s bill. In his testimony, Mr. Greg Walters shows the combined bill

11

impacts of MERC’s proposed rate area consolidation and PGA consolidation.

12

**Table 6: Monthly, Annual and Average Monthly Residential Purchased Gas Cost Impacts by PGA**

	PNG-NNG	PNG-GLGT	PNG-VGT	NMU-NNG	NMU GLGT/VGT/Centra
January	\$0.42	\$3.91	\$(0.68)	\$6.60	(\$8.26)
February	\$0.35	\$3.24	\$(0.56)	\$5.47	(\$6.83)
March	\$0.29	\$2.71	\$(0.47)	\$4.57	(\$5.72)
April	\$0.17	\$1.62	\$(0.28)	\$2.74	(\$3.43)
May	\$0.10	\$0.90	\$(0.16)	\$1.52	(\$1.91)
June	\$0.04	\$0.42	\$(0.07)	\$0.70	(\$0.88)
July	\$0.03	\$0.32	\$(0.06)	\$0.54	(\$0.67)
August	\$0.04	\$0.34	\$(0.06)	\$0.57	(\$0.71)
September	\$0.07	\$0.64	\$(0.11)	\$ 1.09	(\$1.36)
October	\$0.16	\$1.45	\$(0.25)	\$2.45	(\$3.06)
November	\$0.25	\$2.29	\$(0.40)	\$3.87	(\$4.84)
December	\$0.36	\$3.35	\$(0.58)	\$5.66	(\$7.07)
Total	\$2.27	\$21.19	\$(3.68)	\$35.79	(\$44.75)
Monthly Average	\$0.19	\$1.77	\$(0.31)	\$2.98	(\$3.73)

Please see Exhibit \_\_\_\_\_ (GJW-5) attached to the Direct Testimony of Mr. Greg Walters for the calculations underlying the table above.

As shown in Table 6, all customers except those served off of the NNG pipeline and PNG customers served off of the GLGT pipeline will experience a decrease in gas costs following consolidation. The customers who will experience the biggest gas cost impact are those MERC-NMU customers who are served off of the NNG pipeline. These customers make up approximately 8.80% of MERC's total system sales. This rate impact is due to removal of the subsidization of gas costs for these customers by MERC-NMU's customers supplied off the GLGT, VGT, and Centra pipelines, and the resulting PGA rate will reflect the actual gas costs incurred for supplying these customers.

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24

MERC-PNG customers supplied off of the GLGT pipeline will also see an average increase in their monthly gas costs of approximately \$1.77 as indicated in Table 6. The increase in gas costs is primarily due to combining the demand and volumetric costs of GLGT with those of VGT and Centra. As discussed above, costs on VGT have historically been higher than those on GLGT in part due to allocation of NNG capacity to PNG-VGT and NMU. In the 2010-2011 demand entitlement filings, however, MERC did not allocate this capacity to PNG-VGT, and the demand costs on VGT decreased. This in turn will decrease the impact of PGA consolidation on customers currently served by PNG-GLGT from that shown in Table 6.

Q. PLEASE DISCUSS HOW THE CHANGES PROPOSED IN THE DEMAND ENTITLEMENT DOCKETS FILED ON NOVEMBER 1, 2010 AFFECT THE RATE IMPACTS OF YOUR PROPOSAL.

A. As discussed above, MERC has purchased a delivered gas daily call option at Wadena that eliminates the need to allocate NNG costs to customers served off of the VGT pipeline. If approved by the Commission, this change would be effective November 1, 2010. Tables 7 and 8 below show the expected rate impacts to the demand cost of gas and total cost of gas based on the changes implemented in the 2010/2011 Demand Entitlement filings. The per therm demand rates were calculated by dividing the 2010-2011 total demand costs from the 2010-2011 demand entitlement filings by the 2011 sales forecast. The commodity cost of gas and the volumetric cost of gas will not be significantly affected by the changes in the demand entitlement filing.

**Table 7: Demand Cost of Gas (Gas Cost Per Therm)  
Based on 2010/2011 Demand Entitlement Filings**

	<b>Current PGA System</b>	<b>Proposed PGA System</b>	<b>Increase/(Decrease)</b>
<b>PNG-NNG</b>	\$0.15927	\$0.16131	\$0.00204
<b>PNG-GLGT</b>	\$0.08465	\$0.09979	\$0.01514
<b>PNG-VGT</b>	\$0.09343	\$0.09979	\$0.00636
<b>NMU-NNG</b>	\$0.13764	\$0.16131	\$0.02367
<b>NMU-GLGT</b>	\$0.13764	\$0.09979	(\$0.03785)
<b>NMU-VGT</b>	\$0.13764	\$0.09979	(\$0.03785)
<b>NMU-Centra</b>	\$0.13764	\$0.09979	(\$0.03785)

See Exhibit \_\_\_\_\_ (SLG-1) Page 5 of 6 (MERC Proposed Consolidated Demand Cost Comparison Based on 2010/2011 Demand Entitlement Filings) for a graphical representation.

**Table 8: Total Cost of Gas (Gas Cost Per Therm)  
Based on 2010/2011 Demand Entitlement Filings**

	<b>Current PGA System</b>	<b>Proposed PGA System</b>	<b>Increase/(Decrease)</b>
<b>PNG-NNG</b>	\$0.73202	\$0.73614	\$0.00412
<b>PNG-GLGT</b>	\$0.63582	\$0.64626	\$0.01044
<b>PNG-VGT</b>	\$0.64415	\$0.64626	(\$0.00211)
<b>NMU-NNG</b>	\$0.70186	\$0.73614	\$0.03428
<b>NMU-GLGT</b>	\$0.70186	\$0.64626	(\$0.05560)
<b>NMU-VGT</b>	\$0.70186	\$0.64626	(\$0.05560)
<b>NMU-Centra</b>	\$0.70186	\$0.64626	(\$0.05560)

1 See Exhibit \_\_\_\_\_ (SLG-1) Page 6 of 6 (MERC Proposed Consolidated PGA  
 2 Comparison Based on 2010/2011 Demand Entitlement Filings) for a graphical  
 3 representation.

4  
 5 Q. WHAT ARE THE GAS COST IMPACTS ASSOCIATED WITH YOUR PROPOSAL  
 6 FOR RESIDENTIAL CUSTOMERS ASSUMING THE CHANGES PROPOSED IN  
 7 THE 2010/2011 DEMAND ENTITLEMENT FILINGS?

8 A. Table 9 calculates the monthly, annual, and monthly average impacts on cost of gas due  
 9 to PGA consolidation based on the changes proposed in the 2010/2011 Demand  
 10 Entitlement filings.

11  
 12 **Table 9: Monthly, Annual and Average Monthly Residential Purchased**  
 13 **Gas Cost Impacts by PGA Based on 2010/2011 Demand Entitlement Filings**  
 14

	PNG- NNG	PNG- GLGT	PNG- VGT	NMU- NNG	NMU GLGT/VGT/Centra
January	\$0.75	\$1.58	\$0.24	\$5.48	(\$9.21)
February	\$0.62	\$1.31	\$0.20	\$4.54	(\$7.62)
March	\$0.52	\$1.10	\$0.17	\$3.80	(\$6.38)
April	\$0.31	\$0.66	\$0.10	\$2.28	(\$3.83)
May	\$0.17	\$0.37	\$0.06	\$1.27	(\$2.12)
June	\$0.08	\$0.17	\$0.03	\$0.58	(\$0.98)
July	\$0.06	\$0.13	\$0.02	\$0.45	(\$0.75)
August	\$0.06	\$0.14	\$0.02	\$0.47	(\$0.80)
September	\$0.12	\$0.26	\$0.04	\$0.90	(\$1.52)
October	\$0.28	\$0.59	\$0.09	\$2.03	(\$3.42)
November	\$0.44	\$0.93	\$0.14	\$3.22	(\$5.40)
December	\$0.64	\$1.36	\$0.21	\$4.70	(\$7.89)
Total	\$4.07	\$8.58	\$1.30	\$29.72	(\$49.92)
Monthly Average	\$0.34	\$0.71	\$0.11	\$2.48	(\$4.16)

15

1 Please see Exhibit \_\_\_\_ (SLG-3) for the calculations underlying the table above.

2  
3 As shown in Table 9, PNG-GLGT customers would expect to see an average increase in  
4 their monthly cost of gas of approximately \$0.71 compared to an average increase of  
5 \$1.77 indicated in Table 6. As noted above, this smaller increase is due to decreased  
6 demand costs on VGT.

7  
8 MERC-PNG customers served off of the NNG pipeline will also see a slight increase in  
9 their monthly cost of gas of approximately \$0.34 as indicated in Table 9 compared to an  
10 increase of \$0.19 in Table 6. In previous Demand Entitlement filings, NNG capacity was  
11 allocated based on actual delivery point between PNG-NNG and NMU-NNG. In the  
12 2010-2011 Demand Entitlement filings, NNG capacity was allocated based on Design  
13 Day, resulting in an increase in demand costs for PNG-NNG customers.

14  
15 MERC-PNG customers served off of the VGT pipeline will see a very small increase in  
16 their monthly cost of gas of approximately \$0.11. The slight increase would be due to  
17 combining the VGT demand costs with those of the GLGT and Centra pipelines. Since  
18 Centra's demand cost is higher than GLGT and VGT this would result in a minor  
19 increase in demand costs.

20  
21 MERC-NMU customers served off of NNG will see an increase in their average monthly  
22 cost of gas of \$2.47 as the subsidization of these customers by other customers served by  
23 NMU is eliminated. In previous Demand Entitlement filings, NNG capacity was

1 allocated based on actual delivery point between PNG-NNG and NMU-NNG. In the  
2 2010-2011 Demand Entitlement filings, NNG capacity was allocated based on Design  
3 Day, resulting in a decrease in demand costs for NMU-NNG customers.

4  
5 MERC-NMU customers served off of the GLGT, VGT, and Centra pipelines will see a  
6 significant decrease in annual cost of gas of approximately \$4.15 per month as indicated  
7 in Table 9. This decrease is primarily due to a decrease in demand, volumetric and  
8 commodity costs associated with the NNG pipeline.

9  
10 Q. HOW WERE THE IMPACTS ON COST OF GAS OF THE PGA CONSOLIDATION  
11 PROPOSAL CALCULATED?

12 A. The impacts were calculated by taking the average usage per residential customer of the  
13 MERC system as a whole as seen in Exhibit \_\_\_\_\_ (SLG-2) and applying the applicable  
14 increase or decrease of the applicable PGA rate. The calculation of the gas cost impacts  
15 in Table 6 are detailed in Exhibit \_\_\_\_\_ (GJW-5) attached to the Direct Testimony of  
16 Greg Walters. The PGA rates used to calculate the gas cost impacts in Table 9 are those  
17 from the base cost of gas filing adjusted for the changes proposed in the Demand  
18 Entitlement filings. The calculation of the rate impacts in Table 9 are detailed in Exhibit  
19 \_\_\_\_ (SLG-3).

20  
21 Q. WILL THE PROPOSED PGA CONSOLIDATION RESULT IN INTER-PIPELINE OR  
22 INTER-REGIONAL SUBSIDY?

1 A. As discussed above, the Company's proposal will actually eliminate inter-pipeline  
2 subsidization of MERC-NMU's customers supplied off of the NNG pipeline, but does  
3 create a small inter-pipeline subsidy of the VGT PGA customers by the GLGT PGA  
4 customers. However, due to the common source of gas, the ability to move gas between  
5 the GLGT, VGT, and Centra pipelines and the similarity in gas costs on the VGT and  
6 GLGT pipelines MERC believes it is reasonable to treat these pipelines on a consolidated  
7 basis.

8  
9 Q. PLEASE DISCUSS WHETHER ANY CHANGES IN THE CONDITIONS OF  
10 SERVICE ARE SUFFICIENTLY GRADUAL TO AVOID DRASTIC RATE  
11 CHANGES (RATE SHOCK) TO CUSTOMERS.

12 A. Yes, they are. Under MERC's proposal, the consolidated PGA rates would not go into  
13 effect with final rates but instead would be effective on July 1<sup>st</sup> following implementation  
14 of final rates, when there is the least impact on customers' bills as shown in Table 6 and 9  
15 above. For customers experiencing an increase in gas costs, this impact would gradually  
16 increase as gas usage rises in the colder months. Moreover, as shown in the Direct  
17 Testimony of Mr. Walters, residential customers currently in the NMU distribution area  
18 will experience a decrease in distribution rates of \$0.00011 per therm under MERC's rate  
19 area consolidation proposal , which will help to offset any increase for NMU customers  
20 served by the NNG pipeline due to the PGA consolidation. In addition, MERC will also  
21 target the distribution of energy efficiency information to customers in the areas that are  
22 expected to experience gas cost increases, as described in the testimony of Mr. Greg  
23 Walters.

24

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15

**VI. CONCLUSION**

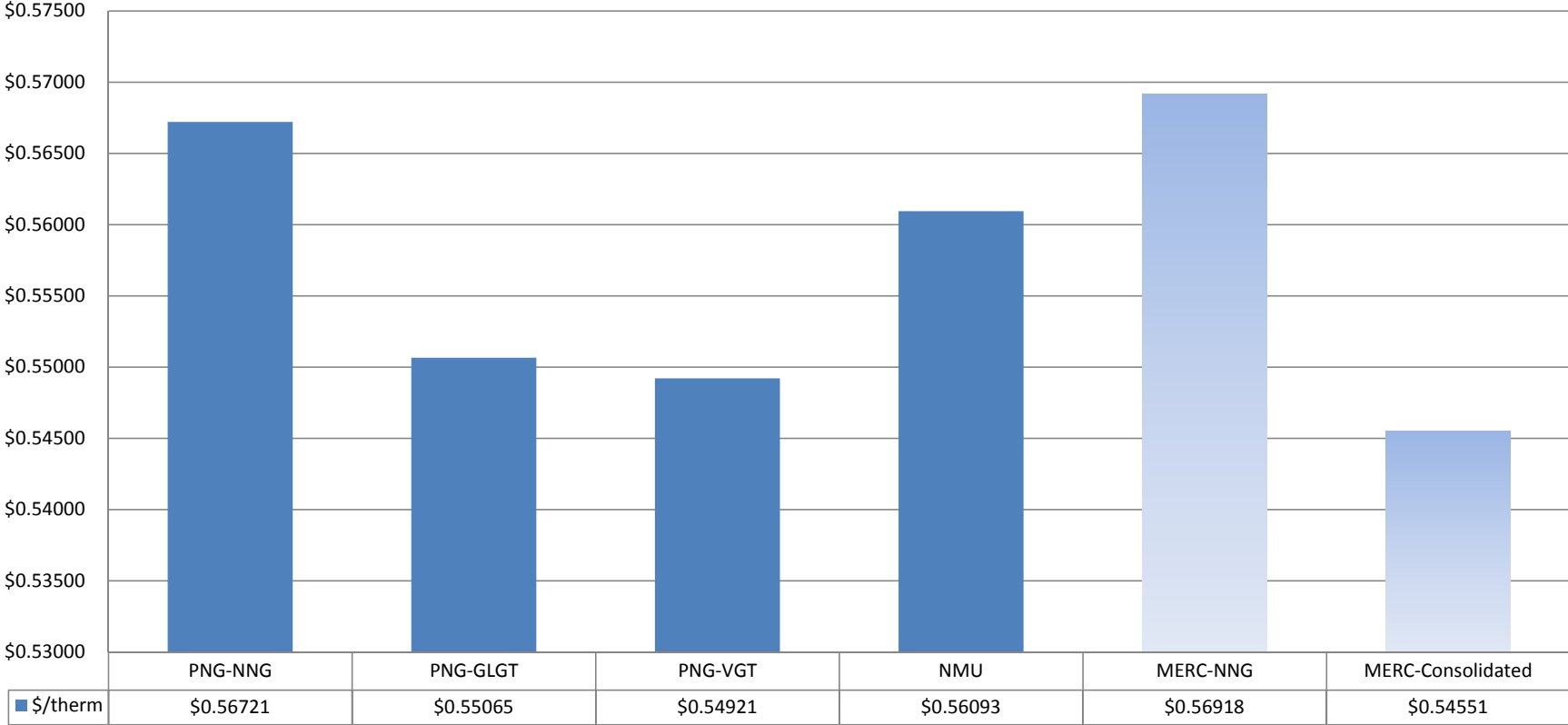
Q. PLEASE PROVIDE A SUMMARY OF YOUR PROPOSAL.

A. I propose that MERC’s current PGA system, with three separate PGAs for MERC-PNG and one PGA for NMU, be changed into a system of two PGAs by consolidating the PGAs for GLGT, VGT, and Centra across the PNG and NMU operating divisions and establishing a single PGA for the NNG pipeline serving both PNG and NMU customers. Consolidating the PGAs would benefit MERC’s ratepayers by minimizing subsidization that is currently in place, removing differences in cost of gas that are not based on the actual costs charged by the pipelines, and resulting in consistent gas costs for the pipelines serving both PNG and NMU communities. In particular, the Company’s proposal would result in a decrease in gas cost for many of MERC’s customers.

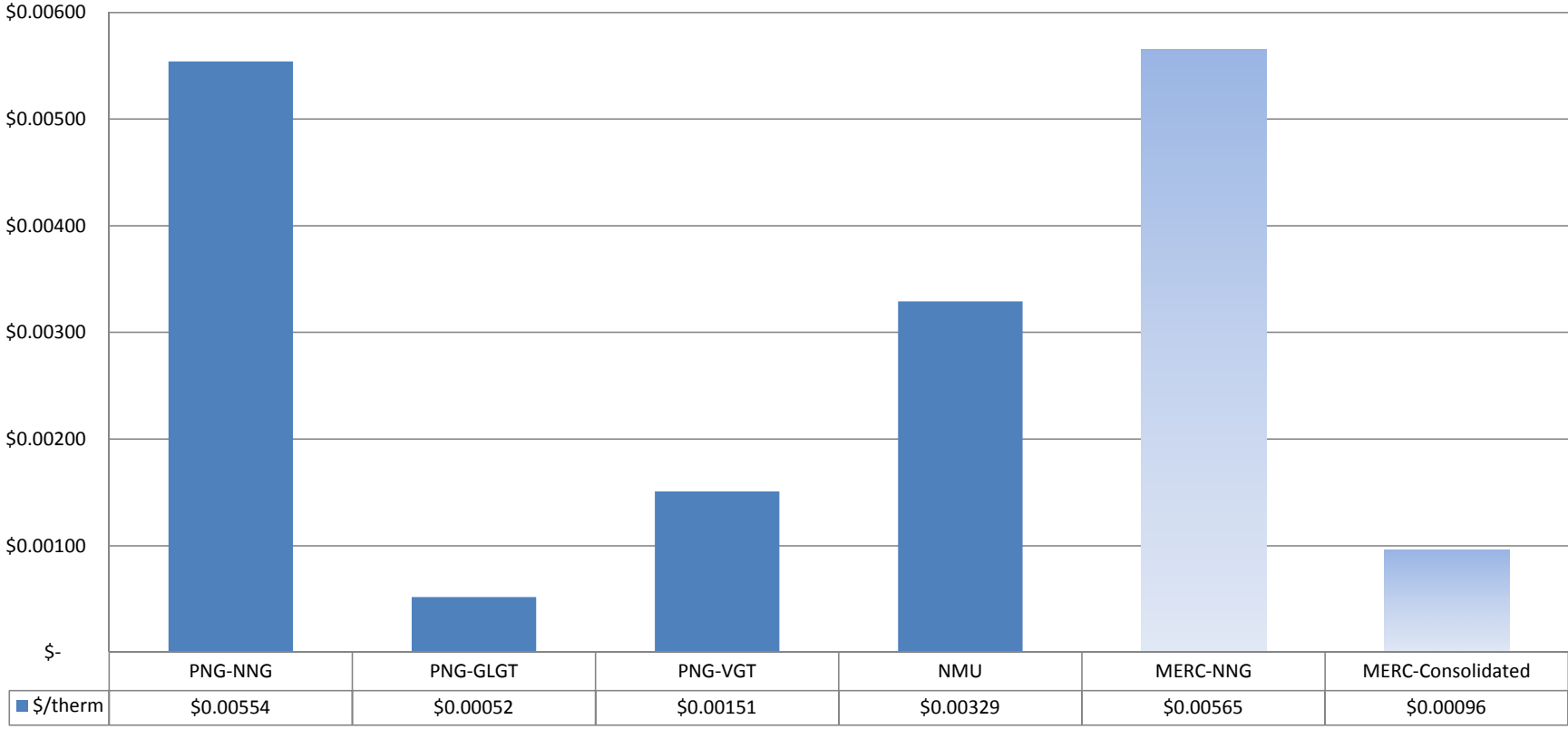
Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

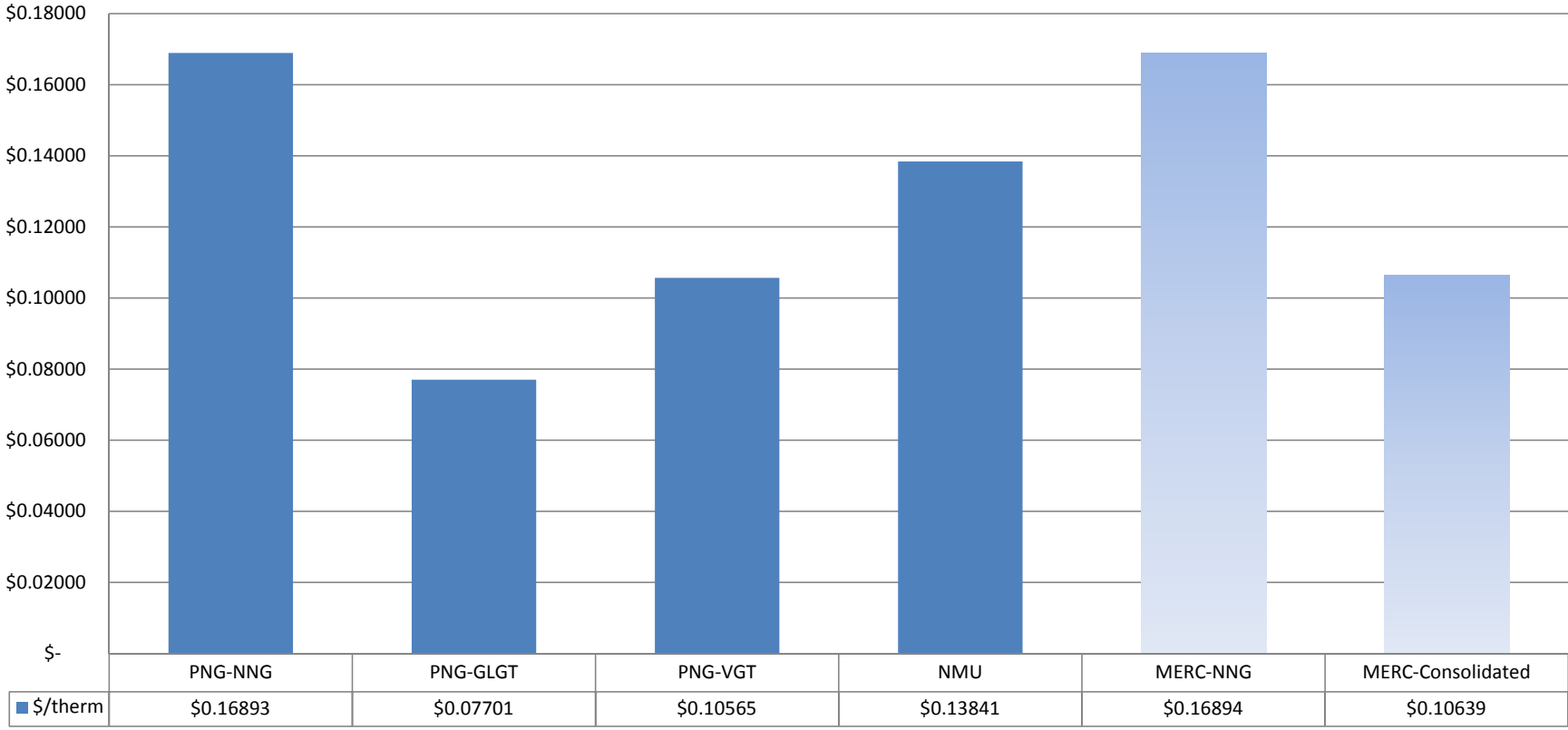
**MERC Proposed Consolidated Commodity Cost Comparison**  
**Current vs Proposed PGA systems**



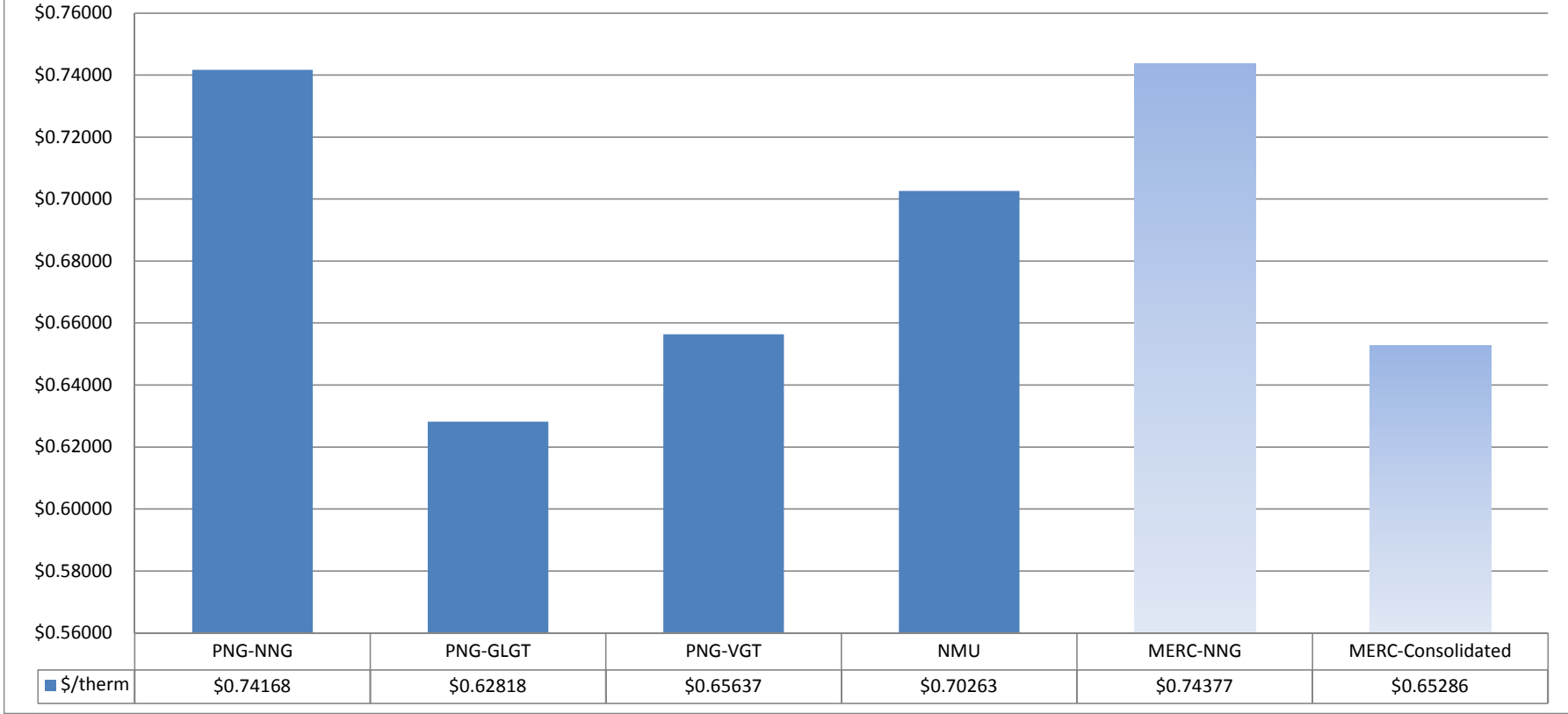
### MERC Proposed Consolidated Volumetric Cost Comparison Current vs Proposed PGA systems



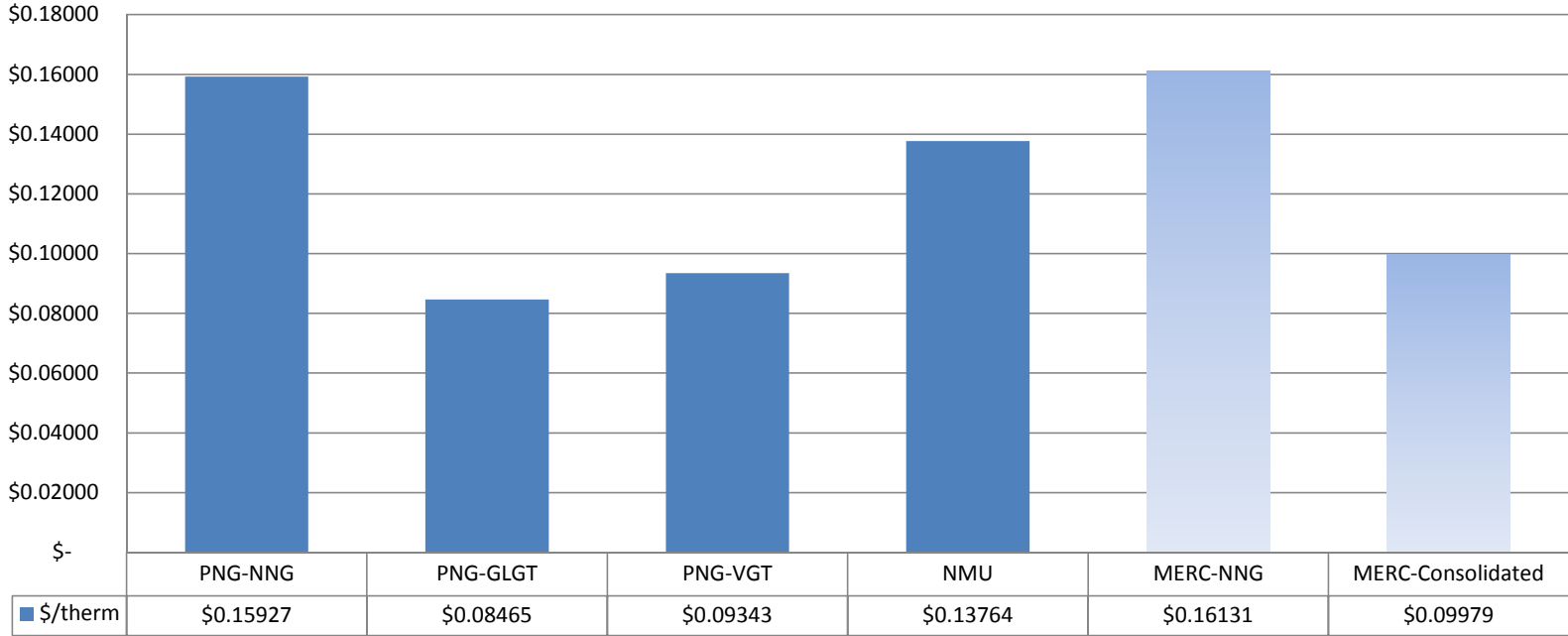
### MERC Proposed Consolidated Demand Cost Comparison Current vs Proposed PGA systems



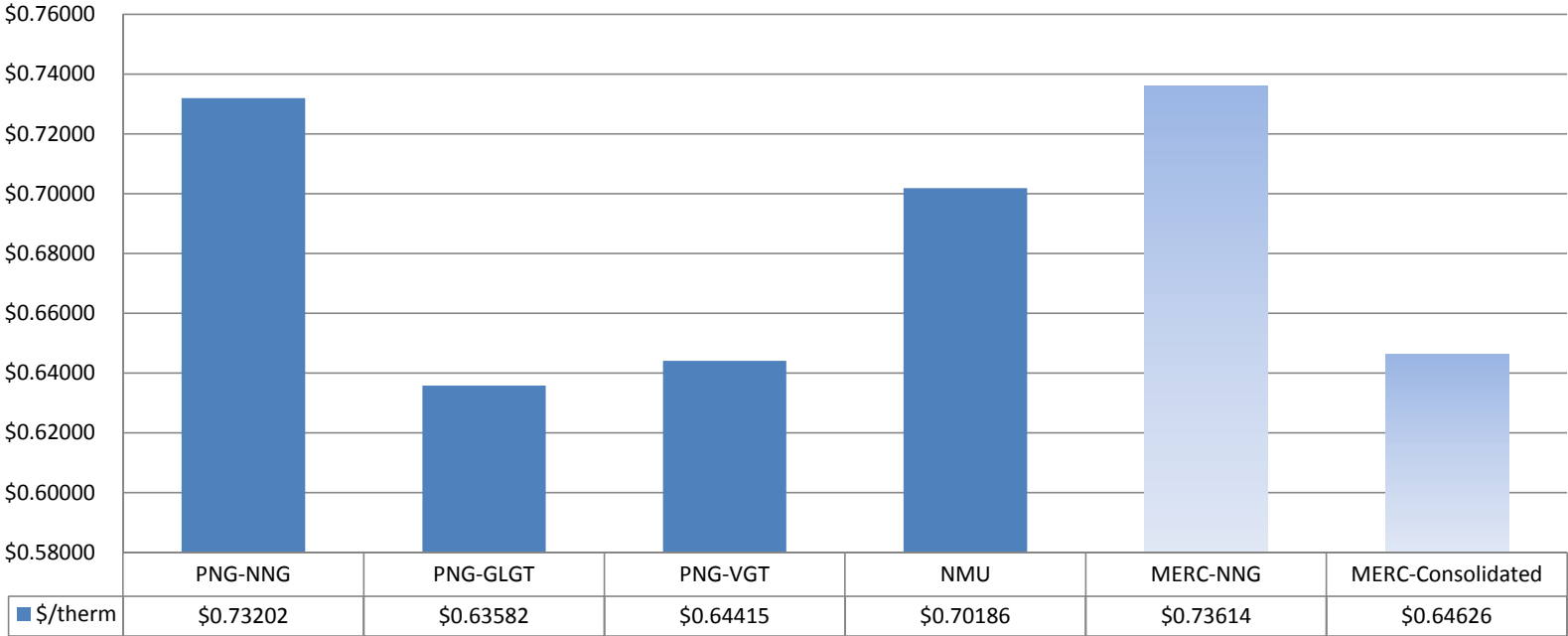
**MERC Proposed Consolidated PGA Comparison**  
**Current vs Proposed PGA systems**



**MERC Proposed Consolidated Demand Cost Comparison**  
**Current vs Proposed PGA Systems**  
**(Based on 2010/2011 Demand Entitlement Filings)**



**MERC Proposed Consolidated PGA Comparison**  
**Current vs Proposed PGA Systems**  
**(Based on 2010/2011 Demand Entitlement Filings)**



	<b>Jan-11</b>	<b>Feb-11</b>	<b>Mar-11</b>	<b>Apr-11</b>	<b>May-11</b>	<b>Jun-11</b>	<b>Jul-11</b>	<b>Aug-11</b>	<b>Sep-11</b>	<b>Oct-11</b>	<b>Nov-11</b>	<b>Dec-11</b>	<b>Total</b>
MERC Monthly Residential Sales	31,038,943	25,686,987	21,484,412	12,893,928	7,160,709	3,307,317	2,532,670	2,679,318	5,115,399	11,510,946	18,206,811	26,592,973	168,210,413
Average Residential Customer Count	189,875	189,875	189,875	189,875	189,875	189,875	189,875	189,875	189,875	189,875	189,875	189,875	189,875
Monthly Sales Ratio	18.45%	15.27%	12.77%	7.67%	4.26%	1.97%	1.51%	1.59%	3.04%	6.84%	10.82%	15.81%	100.00%
Average Monthly Usage/Customer	163.5	135.3	113.2	67.9	37.7	17.4	13.3	14.1	26.9	60.6	95.9	140.1	886.0



**Comparison of One Set of Distribution Rates and Four PGAs with Two Sets of Distribution Rates and Four PGAs (Distribution Rate Consolidation)**

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Monthly Average
NNG	\$ 1.46	\$ 1.21	\$ 1.01	\$ 0.61	\$ 0.34	\$ 0.16	\$ 0.12	\$ 0.13	\$ 0.24	\$ 0.54	\$ 0.86	\$ 1.25	\$ 7.93	\$ 0.66
Viking	\$ 1.46	\$ 1.21	\$ 1.01	\$ 0.61	\$ 0.34	\$ 0.16	\$ 0.12	\$ 0.13	\$ 0.24	\$ 0.54	\$ 0.86	\$ 1.25	\$ 7.93	\$ 0.66
Great Lakes	\$ 1.46	\$ 1.21	\$ 1.01	\$ 0.61	\$ 0.34	\$ 0.16	\$ 0.12	\$ 0.13	\$ 0.24	\$ 0.54	\$ 0.86	\$ 1.25	\$ 7.93	\$ 0.66
NMU Consolidated	\$ (5.31)	\$ (4.40)	\$ (3.68)	\$ (2.21)	\$ (1.23)	\$ (0.57)	\$ (0.43)	\$ (0.46)	\$ (0.88)	\$ (1.97)	\$ (3.12)	\$ (4.55)	\$ (28.79)	\$ (2.40)

**Comparison of One Set of Distribution Rates and Two PGAs with One Set of Distribution Rates and Four PGAs (PGA Consolidation)**

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Monthly Average
NNG	\$ 0.75	\$ 0.62	\$ 0.52	\$ 0.31	\$ 0.17	\$ 0.08	\$ 0.06	\$ 0.06	\$ 0.12	\$ 0.28	\$ 0.44	\$ 0.64	\$ 4.07	\$ 0.34
Viking	\$ 0.24	\$ 0.20	\$ 0.17	\$ 0.10	\$ 0.06	\$ 0.03	\$ 0.02	\$ 0.02	\$ 0.04	\$ 0.09	\$ 0.14	\$ 0.21	\$ 1.30	\$ 0.11
Great Lakes	\$ 1.58	\$ 1.31	\$ 1.10	\$ 0.66	\$ 0.37	\$ 0.17	\$ 0.13	\$ 0.14	\$ 0.26	\$ 0.59	\$ 0.93	\$ 1.36	\$ 8.58	\$ 0.71
NMU Consolidated	\$ (9.21)	\$ (7.62)	\$ (6.38)	\$ (3.83)	\$ (2.12)	\$ (0.98)	\$ (0.75)	\$ (0.80)	\$ (1.52)	\$ (3.42)	\$ (5.40)	\$ (7.89)	\$ (49.92)	\$ (4.16)
NMU-NNG	\$ 5.48	\$ 4.54	\$ 3.80	\$ 2.28	\$ 1.27	\$ 0.58	\$ 0.45	\$ 0.47	\$ 0.90	\$ 2.03	\$ 3.22	\$ 4.70	\$ 29.72	\$ 2.48

**Comparison of One Set of Distribution Rates and Two PGAs with Two Sets of Distribution Rates and Four PGAs (Distribution Rate and PGA Consolidation)**

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Monthly Average
NNG	\$ 2.21	\$ 1.83	\$ 1.53	\$ 0.92	\$ 0.51	\$ 0.24	\$ 0.18	\$ 0.19	\$ 0.36	\$ 0.82	\$ 1.30	\$ 1.90	\$ 12.00	\$ 1.00
Viking	\$ 1.70	\$ 1.41	\$ 1.18	\$ 0.71	\$ 0.39	\$ 0.18	\$ 0.14	\$ 0.15	\$ 0.28	\$ 0.63	\$ 1.00	\$ 1.46	\$ 9.23	\$ 0.77
Great Lakes	\$ 3.05	\$ 2.52	\$ 2.11	\$ 1.27	\$ 0.70	\$ 0.32	\$ 0.25	\$ 0.26	\$ 0.50	\$ 1.13	\$ 1.79	\$ 2.61	\$ 16.51	\$ 1.38
NMU Consolidated	\$ (14.52)	\$ (12.02)	\$ (10.05)	\$ (6.03)	\$ (3.35)	\$ (1.55)	\$ (1.19)	\$ (1.25)	\$ (2.39)	\$ (5.39)	\$ (8.52)	\$ (12.44)	\$ (78.70)	\$ (6.56)
NMU-NNG	\$ 0.17	\$ 0.14	\$ 0.12	\$ 0.07	\$ 0.04	\$ 0.02	\$ 0.01	\$ 0.01	\$ 0.03	\$ 0.06	\$ 0.10	\$ 0.15	\$ 0.93	\$ 0.08

One Set of Distribution Rates, Two PGAs

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Monthly Average
Monthly Sales Ratio	18.45%	15.27%	12.77%	7.67%	4.26%	1.97%	1.51%	1.59%	3.04%	6.84%	10.82%	15.81%	100.00%	
Therms/Customer	163.5	135.3	113.2	67.9	37.7	17.4	13.3	14.1	26.9	60.6	95.9	140.1	886.0	73.8
<b>NNG</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.73614													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 120.35	\$ 99.60	\$ 83.30	\$ 49.99	\$ 27.76	\$ 12.82	\$ 9.82	\$ 10.39	\$ 19.83	\$ 44.63	\$ 70.60	\$ 103.11	\$ 652.22	\$ 54.35
Total Revenue	\$ 165.41	\$ 138.52	\$ 117.41	\$ 74.27	\$ 45.47	\$ 26.11	\$ 22.22	\$ 22.96	\$ 35.19	\$ 67.32	\$ 100.95	\$ 143.07	\$ 958.91	\$ 79.91
<b>Viking</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.64626													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 105.66	\$ 87.44	\$ 73.13	\$ 43.89	\$ 24.37	\$ 11.26	\$ 8.62	\$ 9.12	\$ 17.41	\$ 39.18	\$ 61.98	\$ 90.52	\$ 572.59	\$ 47.72
Total Revenue	\$ 150.71	\$ 126.36	\$ 107.24	\$ 68.16	\$ 42.08	\$ 24.55	\$ 21.02	\$ 21.69	\$ 32.77	\$ 61.87	\$ 92.33	\$ 130.48	\$ 879.27	\$ 73.27
<b>Great Lakes</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.64626													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 105.66	\$ 87.44	\$ 73.13	\$ 43.89	\$ 24.37	\$ 11.26	\$ 8.62	\$ 9.12	\$ 17.41	\$ 39.18	\$ 61.98	\$ 90.52	\$ 572.59	\$ 47.72
Total Revenue	\$ 150.71	\$ 126.36	\$ 107.24	\$ 68.16	\$ 42.08	\$ 24.55	\$ 21.02	\$ 21.69	\$ 32.77	\$ 61.87	\$ 92.33	\$ 130.48	\$ 879.27	\$ 73.27
<b>NMU-Consolidated</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.64626													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 105.66	\$ 87.44	\$ 73.13	\$ 43.89	\$ 24.37	\$ 11.26	\$ 8.62	\$ 9.12	\$ 17.41	\$ 39.18	\$ 61.98	\$ 90.52	\$ 572.59	\$ 47.72
Total Revenue	\$ 150.71	\$ 126.36	\$ 107.24	\$ 68.16	\$ 42.08	\$ 24.55	\$ 21.02	\$ 21.69	\$ 32.77	\$ 61.87	\$ 92.33	\$ 130.48	\$ 879.27	\$ 73.27
<b>NMU-NNG</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.73614													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 120.35	\$ 99.60	\$ 83.30	\$ 49.99	\$ 27.76	\$ 12.82	\$ 9.82	\$ 10.39	\$ 19.83	\$ 44.63	\$ 70.60	\$ 103.11	\$ 652.22	\$ 54.35
Total Revenue	\$ 165.41	\$ 138.52	\$ 117.41	\$ 74.27	\$ 45.47	\$ 26.11	\$ 22.22	\$ 22.96	\$ 35.19	\$ 67.32	\$ 100.95	\$ 143.07	\$ 958.91	\$ 79.91

One Set of Distribution Rates, Four PGAs

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Monthly Average
Monthly Sales Ratio	18.45%	15.27%	12.77%	7.67%	4.26%	1.97%	1.51%	1.59%	3.04%	6.84%	10.82%	15.81%	100.00%	
Therms/Customer	163.5	135.3	113.2	67.9	37.7	17.4	13.3	14.1	26.9	60.6	95.9	140.1	886.0	73.8
<b>NNG</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.73155													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 119.60	\$ 98.98	\$ 82.78	\$ 49.68	\$ 27.59	\$ 12.74	\$ 9.76	\$ 10.32	\$ 19.71	\$ 44.35	\$ 70.16	\$ 102.47	\$ 648.15	\$ 54.01
Total Revenue	\$ 164.66	\$ 137.90	\$ 116.90	\$ 73.95	\$ 45.29	\$ 26.03	\$ 22.16	\$ 22.89	\$ 35.07	\$ 67.04	\$ 100.51	\$ 142.43	\$ 954.84	\$ 79.57
<b>Viking</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.64479													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 105.42	\$ 87.24	\$ 72.97	\$ 43.79	\$ 24.32	\$ 11.23	\$ 8.60	\$ 9.10	\$ 17.37	\$ 39.09	\$ 61.83	\$ 90.32	\$ 571.28	\$ 47.61
Total Revenue	\$ 150.47	\$ 126.16	\$ 107.08	\$ 68.06	\$ 42.02	\$ 24.52	\$ 21.00	\$ 21.67	\$ 32.73	\$ 61.78	\$ 92.19	\$ 130.28	\$ 877.97	\$ 73.16
<b>Great Lakes</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.63658													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 104.07	\$ 86.13	\$ 72.04	\$ 43.23	\$ 24.01	\$ 11.09	\$ 8.49	\$ 8.98	\$ 17.15	\$ 38.60	\$ 61.05	\$ 89.17	\$ 564.01	\$ 47.00
Total Revenue	\$ 149.13	\$ 125.05	\$ 106.15	\$ 67.50	\$ 41.71	\$ 24.38	\$ 20.89	\$ 21.55	\$ 32.51	\$ 61.28	\$ 91.40	\$ 129.13	\$ 870.70	\$ 72.56
<b>NMU</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.21748													
PGA Rate	\$ 0.70260													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 35.56	\$ 29.42	\$ 24.61	\$ 14.77	\$ 8.20	\$ 3.79	\$ 2.90	\$ 3.07	\$ 5.86	\$ 13.19	\$ 20.86	\$ 30.46	\$ 192.69	\$ 16.06
PGA Revenue	\$ 114.87	\$ 95.06	\$ 79.51	\$ 47.72	\$ 26.50	\$ 12.24	\$ 9.37	\$ 9.92	\$ 18.93	\$ 42.60	\$ 67.38	\$ 98.41	\$ 622.50	\$ 51.88
Total Revenue	\$ 159.92	\$ 133.99	\$ 113.62	\$ 71.99	\$ 44.20	\$ 25.53	\$ 21.77	\$ 22.48	\$ 34.29	\$ 65.29	\$ 97.73	\$ 138.38	\$ 929.19	\$ 77.43

Two Sets of Distribution Rates, Four PGAs

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Monthly Average
Monthly Sales Ratio	18.45%	15.27%	12.77%	7.67%	4.26%	1.97%	1.51%	1.59%	3.04%	6.84%	10.82%	15.81%	100.00%	
Therms/Customer	163.5	135.3	113.2	67.9	37.7	17.4	13.3	14.1	26.9	60.6	95.9	140.1	886.0	73.8
<b>NNG</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.20853													
PGA Rate	\$ 0.73155													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 34.09	\$ 28.21	\$ 23.60	\$ 14.16	\$ 7.87	\$ 3.63	\$ 2.78	\$ 2.94	\$ 5.62	\$ 12.64	\$ 20.00	\$ 29.21	\$ 184.76	\$ 15.40
PGA Revenue	\$ 119.60	\$ 98.98	\$ 82.78	\$ 49.68	\$ 27.59	\$ 12.74	\$ 9.76	\$ 10.32	\$ 19.71	\$ 44.35	\$ 70.16	\$ 102.47	\$ 648.15	\$ 54.01
Total Revenue	\$ 163.19	\$ 136.69	\$ 115.88	\$ 73.35	\$ 44.96	\$ 25.88	\$ 22.04	\$ 22.77	\$ 34.83	\$ 66.50	\$ 99.65	\$ 141.18	\$ 946.91	\$ 78.91
<b>Viking</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.20853													
PGA Rate	\$ 0.64479													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 34.09	\$ 28.21	\$ 23.60	\$ 14.16	\$ 7.87	\$ 3.63	\$ 2.78	\$ 2.94	\$ 5.62	\$ 12.64	\$ 20.00	\$ 29.21	\$ 184.76	\$ 15.40
PGA Revenue	\$ 105.42	\$ 87.24	\$ 72.97	\$ 43.79	\$ 24.32	\$ 11.23	\$ 8.60	\$ 9.10	\$ 17.37	\$ 39.09	\$ 61.83	\$ 90.32	\$ 571.28	\$ 47.61
Total Revenue	\$ 149.01	\$ 124.95	\$ 106.06	\$ 67.45	\$ 41.68	\$ 24.37	\$ 20.88	\$ 21.54	\$ 32.49	\$ 61.24	\$ 91.33	\$ 129.03	\$ 870.04	\$ 72.50
<b>Great Lakes</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.20853													
PGA Rate	\$ 0.63658													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 34.09	\$ 28.21	\$ 23.60	\$ 14.16	\$ 7.87	\$ 3.63	\$ 2.78	\$ 2.94	\$ 5.62	\$ 12.64	\$ 20.00	\$ 29.21	\$ 184.76	\$ 15.40
PGA Revenue	\$ 104.07	\$ 86.13	\$ 72.04	\$ 43.23	\$ 24.01	\$ 11.09	\$ 8.49	\$ 8.98	\$ 17.15	\$ 38.60	\$ 61.05	\$ 89.17	\$ 564.01	\$ 47.00
Total Revenue	\$ 147.67	\$ 123.84	\$ 105.14	\$ 66.90	\$ 41.37	\$ 24.22	\$ 20.77	\$ 21.43	\$ 32.27	\$ 60.74	\$ 90.55	\$ 127.88	\$ 862.77	\$ 71.90
<b>NMU</b>														
Customer Charge Rate	\$ 9.50													
Distribution Rate	\$ 0.24997													
PGA Rate	\$ 0.70260													
Customer Charge Revenue	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 9.50	\$ 114.00	\$ 9.50
Distribution Revenue	\$ 40.87	\$ 33.82	\$ 28.29	\$ 16.98	\$ 9.43	\$ 4.35	\$ 3.33	\$ 3.53	\$ 6.74	\$ 15.16	\$ 23.97	\$ 35.01	\$ 221.47	\$ 18.46
PGA Revenue	\$ 114.87	\$ 95.06	\$ 79.51	\$ 47.72	\$ 26.50	\$ 12.24	\$ 9.37	\$ 9.92	\$ 18.93	\$ 42.60	\$ 67.38	\$ 98.41	\$ 622.50	\$ 51.88
Total Revenue	\$ 165.23	\$ 138.38	\$ 117.30	\$ 74.19	\$ 45.43	\$ 26.09	\$ 22.21	\$ 22.94	\$ 35.17	\$ 67.25	\$ 100.85	\$ 142.93	\$ 957.98	\$ 79.83