

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of AQUILA NETWORKS-	)	
MGU for authority to implement a gas cost recovery	)	
Plan and factors for the 12-month period ending	)	Case No. U-14715
March 31, 2007.	)	

TESTIMONY AND EXHIBITS
OF
FRANK J. HOLLEWA
ON BEHALF OF
THE RESIDENTIAL RATEPAYER CONSORTIUM

May 25, 2006

1 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.**

2 **A.** My name is Frank J. Hollewa. I am an independent energy consultant doing
3 business as EPEC (Energy Planning and Engineering Consultants). My office is
4 at 6182 Grovedale Court, Suite 100, Alexandria, Virginia 22310.

5 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EMPLOYMENT**
6 **EXPERIENCE.**

7 **A.** I was employed by Washington Gas Light Company for 33 years. At the time of
8 my retirement, I held the position of Senior Vice President of Distribution, Gas
9 Supply and General Services. The responsibilities of this position included the
10 repair, installation and maintenance of all transmission and distribution facilities;
11 system design; system control; gas supply planning; gas acquisition; peak shaving
12 plants; storage field; total energy facilities; Federal Energy Regulatory
13 Commission (FERC) related matters; interface with interstate pipelines; general
14 structures maintenance and improvements; fleet acquisition and maintenance;
15 and interface with three (3) local Public Service Commissions in Maryland,
16 Virginia and the District of Columbia relating to operating matters. The total
17 scope of my position encompassed approximately 50% of all employees at
18 Washington Gas Light. Much of my knowledge and experience was obtained on
19 the job at Washington Gas Light. I was employed there in 1963 at the age of 19
20 as a union grade clerk in the Gas Supply Department. As my knowledge and
21 responsibilities increased, I moved to Staff Assistant; Staff Supervisor; Assistant
22 to the Vice President, Gas Supply; and in 1982 at the age of 38, I became Vice

1 President, Gas Supply. At that time, the Gas Supply Department had over 250
2 employees and represented approximately 10% of the Company manpower.
3 During the period from 1970 to 1995, I participated as an expert witness in
4 approximately 20 formal rate proceedings at the Maryland Public Service
5 Commission ("PSC"), District of Columbia PSC, Virginia State Corporation
6 Commission, and the FERC. I was well known throughout the gas industry and
7 participated as a speaker and panelist at numerous industry gatherings. I was on
8 the Board of Directors of Associated Gas Distributors ("AGD") and Gas Industry
9 Standards Board ("GISB") as well as a member of the Institute of Gas Technology
10 ("IGT") Task Force on Gas Quality at the time of my retirement.
11 For the past eleven years, I have operated EPEC consulting. During that time, I
12 have participated in numerous cases for the New Jersey Division of the Ratepayer
13 Advocate, the Ohio Consumers' Counsel, and the West Virginia Consumer
14 Advocate Division. Since 1999, I have participated in all GCR Plan and
15 Reconciliation Cases involving Michigan's four (4) largest gas distribution
16 companies for the Residential Ratepayer Consortium.

17 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

18 **A.** I have been retained by the Residential Ratepayer Consortium ("RRC") to make
19 an independent analysis and evaluation of the gas cost recovery plan filed by
20 Michigan Gas Utilities Corporation ("MGU" or the "Company") for the 12-month
21 period April 2006 thru March 2007.
22

1 **Q. WHAT DOCUMENTS HAVE YOU REVIEWED IN THIS CASE?**

2 **A.** I have reviewed the testimony and exhibits filed by the Company in this case and
3 MGU's responses to data requests.

4 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

5 **A.** First, I recommend amending MGU's base ceiling GCR factor to \$9.3196 per Mcf
6 and changing the Company's Contingent GCR Factor Matrix (CM) to incorporate
7 a \$3.00 cap on increases in the NYMEX price forecast with Fractional Multipliers
8 of 1.00 for the 1st quarter, 0.80 for the 2nd quarter, 0.60 for the 3rd quarter, and
9 0.40 for the 4th quarter of the 2006-2007 GCR period.

10 Second, I make recommendations regarding adjustments to MGU's annual and
11 monthly GCR requirements, the Company's planned storage requirements, its
12 plan to accommodate colder-than-normal (CTN) weather, a reduction in the
13 current level of MGU's firm transportation, and that the Company file a plan for
14 capacity release credits.

15 **Q. WHAT IS THE CEILING GCR FACTOR MGU IS REQUESTING ?**

16 **A.** In its Notice of Hearing and in Exhibit A-1, MGU indicates that \$14.1603 per
17 Mcf is the ceiling GCR factor the Company is requesting in this case. However,
18 in a letter to the Commission's Executive Secretary dated April 27, 2006
19 (Document No. 0021 in the MPSC's Electronic Case Filings for this case),
20 MGU's counsel states that the Company's request for a gas cost tracker for
21 company use-and-lost-and-unaccounted-for is being withdrawn. Based on the
22 information in Exhibit A-2, page 2, that tracker represents \$.1198 per Mcf of the

1 Company's requested ceiling GCR factor. Therefore, I conclude that MGU is
2 now requesting a ceiling GCR factor of \$14.0405 per Mcf.

3 **Q. WHAT ARE YOUR FINDINGS REGARDING THE COMPANY'S**
4 **PROPOSED CEILING GCR FACTOR?**

5 The Company's requested ceiling GCR factor includes \$1.7447 per Mcf for a
6 "Probability Weighted Price Risk Factor" (PWPRF). The RRC requested
7 clarification of the PWPRF in its discovery question 01-RRC-17 which is
8 presented with this testimony as Exhibit RRC-1 (FJH-1). MGU's response states
9 that the PWPRF is only utilized for the establishment of the GCR ceiling factor in
10 the Company's initial filing. It is not incorporated into the Contingent GCR
11 Factor Matrix (CM).

12 My examination of MGU's proposed CM in Exhibit A-11 reveals that, because
13 the Company proposes to set its ceiling GCR factor at \$14.0405 per Mcf, the CM
14 only becomes applicable for NYMEX increases of \$1.75 to \$2.00 per Mcf.

15 Likewise, MGU's proposed NYMEX Futures Update one week prior to the date
16 for motions to strike would be a moot exercise unless the NYMEX increases were
17 \$1.75 per Mcf or greater. Exhibit RRC-1 (FJH-1) also indicates that the NYMEX
18 Futures Update would not result in a GCR factor lower than the "Base GCR
19 Factor" of \$12.2978 per Mcf. Therefore, the PWPRF virtually eliminates use of
20 the CM as well as the NYMEX Futures Update because MGU would already have
21 a ceiling GCR factor of \$14.0405 per Mcf and a base GCR factor no lower than
22 \$12.2978 per Mcf.

1 A PWPRF measures both the upside and downside price probabilities in the
2 NYMEX natural gas futures. In my opinion, it is wrong to ignore the downside
3 price probability and apply the PWPRF only to set an upper price estimate. The
4 only possible rational use of a PWPRF Factor would be to set the upper limit of
5 the CM.

6 My conclusion is that there is no factual basis for including a PWPRF in setting
7 the ceiling for the GCR factor that MGU may bill its customers in this case. The
8 GCR factor MGU is charging in April and May 2006 is \$9.3196 per Mcf. That is
9 \$4.7209 per Mcf *lower than* the Company's requested ceiling GCR factor.

10 MGU's proposed CM could add approximately \$2.00 per Mcf to the \$12.2978 per
11 Mcf "Base GCR Factor" identified in Exhibit A-11, potentially increasing the
12 GCR ceiling price to approximately \$14.30 per Mcf – an amount that is \$4.98 per
13 Mcf *greater than* the April and May 2006 billed GCR factor. The Commission
14 should find that \$12.298 per Mcf is the numeric value that is MGU's filed ceiling
15 GCR factor in this case with no consideration given to the Company's request for
16 a PWPRF.

17 **Q. WHAT CONCLUSIONS DID YOU REACH REGARDING THE LEVEL**
18 **AT WHICH MGU'S "BASE GCR FACTOR" IS SET?**

19 **A.** Because of changes that have occurred since December 2005 when MGU filed
20 its 2006-2007 GCR Plan, the data shown in Exhibit A-1 are not reasonable
21 projections of the Company's gas costs in April 2006-March 2007. The
22 Company's base ceiling GCR factor of \$12.2978 per Mcf significantly overstates

1 the billing charge necessary to recover MGU's gas costs in the 2006-2007 GCR
2 period. Later in this testimony, I discuss how MGU's GCR factor and its CM
3 should be adjusted to reflect the changes that have occurred since December
4 2005.

5 It is important that MGU's proposed base GCR factor be adjusted to more closely
6 reflect current market conditions and send accurate pricing signals as soon as
7 possible. The existing price spread between the actual GCR factor that MGU is
8 billing its customers and the maximum allowable GCR factor is large enough to
9 create attractive marketing opportunities for gas suppliers participating in the Gas
10 Customer Choice (GCC) program¹. This price spread may foster confusion for
11 customers that will work to their financial detriment.

12 An example of this problem would be a marketer offering a fixed price of \$11.50
13 for a year versus the base ceiling GCR factor of \$12.2978 filed by MGU. The
14 Marketer could further claim that the Company's price could be lower, but could
15 also increase to \$14.30 based on the proposed CM. Under these circumstances,
16 marketers can take unfair advantage of uninformed GCR customers without risk
17 and at large profit margins. The hypothetical price of \$11.50 would be \$2.18
18 greater than the Company's GCR Factor of \$9.32 for April and May 2006. The
19 basis differentials, demand charges and fuel are already incorporated in the

¹ I recognize that currently, there is only one alternative supplier in MGU's service territory who is serving the commercial and industrial classes. The price spread I have identified could attract additional alternative suppliers to MGU's service territory.

1 Company's April and May GCR factor and the assumption is that the same costs
2 would be incurred by the marketer. Therefore, a GCR customer who thinks that
3 she or he is saving \$0.82/Mcf by signing up could, in fact, be paying
4 approximately \$2.18/Mcf more for her or his gas commodity costs.

5 In my opinion, this situation is not the operation of a competitive market
6 envisioned by the GCC Program. Rather, it is the application of opportunistic
7 solicitation resulting from a volatile marketplace for natural gas. The drop in the
8 price forecast from December 2005 when MGU made its GCR filing and March
9 2006 is the direct cause of this large spread, not market competition.

10 To date, prior adjustments to the base GCR factor have been upward to recognize
11 price increases after the plan filing. The Commission has approved use of the
12 CM based in part on its view that a large under recovery by the Company would
13 only create market distortions for both the plan year and the following year. The
14 exact reverse has now occurred. Downward prices will create market distortions
15 and send incorrect price signals for the 2006-2007 GCR Plan year. This fosters
16 the conditions that may cause customers to make bad choices and incur higher
17 commodity costs for the next 12 months.

18 I recognize that no one can predict with certainty that an offer of \$11.50 will be
19 \$2.18 more expensive than the Company's billed GCR factor over the next 12
20 months. However, in making a decision whether to lock in the price offered by
21 an alternative gas supplier, the customer should be armed with the knowledge of
22 the GCR factor that her or his local gas distribution company is currently billing

1 and what it is likely to charge over the GCR period based on current price
2 projections. The Company's filed base GCR factor does not do that and it sends
3 an incorrect price signal to the customer.

4 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING MGU'S GCR**
5 **FACTOR?**

6 **A.** Based on the Company's decision to bill an April and May 2006 GCR factor of
7 \$9.3196 per Mcf, I have reviewed all of the material provided in response to
8 discovery to determine if \$9.3196/Mcf is a reasonable estimate for the balance of
9 2006-2007 GCR period.

10 Exhibit A-6, page 1 shows the Futures Price based on the five-day average
11 occurring between December 1-7, 2005 for the period from April 2006 through
12 March 2007. Mr. Ono describes the six-step process the Company uses to
13 develop its pricing assumptions on Pages 18 and 19 of his testimony.

14 The RRC submitted a discovery question to MGU asking the Company to update
15 the price forecast from the first five trading days in December to the first five
16 trading days in April. Mr. Huzzey, who is adopting Mr. Ono's testimony,
17 prepared the Company's response to a data request identified as 01-RRC-18
18 which is included in my testimony as Exhibit RRC-2 (FJH-2). The response to
19 this data request shows that this updating results in a reduction to Projected Gas
20 Cost of \$65,356,924 and a reduction of \$2.9074 per Mcf in the GCR factor from
21 \$12.2978 per Mcf to \$9.3904 per Mcf.

22 I will note that the average price of \$8.6884 shown on Attachment 01-RRC-18

1 in Exhibit RRC-2 (FJH-2) was developed by MGU using March 29 and April 4-7,
2 2006 futures prices. The first five trading days in April were 4/3-4/7/06 and
3 resulted in an average price of \$8.6665.

4 Even though prices increased later in April, the month ended with a closing price
5 for May of \$7.198 per Mcf. That was only \$0.18 higher than the futures price for
6 May of \$7.019 per Mcf in the 4/3-4/7/06 average. For comparison purposes, the
7 average price for the 12-month strip for the first five trading days in May (5/1-
8 5/5/06) was \$8.7687 per Mcf (using \$7.233 per Mcf for the April Close and
9 \$7.198 per Mcf for the May Close); it was \$8.7277 per Mcf for the week of 5/8-
10 5/12/06; and \$8.2744 per Mcf on 5/18/06.

11 If the GCR Factor is reduced to \$9.3904 per Mcf based on an average 12-month
12 NYMEX price of \$8.6884 as indicated by the Company in response to 01-RRC-
13 18, then a GCR Factor of \$9.3196 (the actual factor billed for April and May
14 2006) would correspond to an average 12-month NYMEX price of \$8.6176.

15 Based on the above data, I recommend that \$9.3196 per Mcf is a reasonable level
16 for the Base GCR Factor.

17 **Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO MGU'S**
18 **CONTINGENCY MECHANISM?**

19 **A.** In order to recognize the potential for continued price volatility, I am
20 recommending that the Contingency Mechanism (CM) have a \$3.00 cap on
21 increases in the NYMEX price instead of the \$2.00 filed by the Company. This
22 would result in a maximum GCR factor of \$12.3196 per Mcf for the 1st Quarter

1 which is slightly higher than the Company's proposed base ceiling GCR factor.

2 This would serve to minimize customer confusion and provide the choice of GCR
3 service at \$9.3196/Mcf now and up to \$12.3196/Mcf for 12 months and would
4 provide a more realistic comparison to the guaranteed price from marketers.

5 Absent the implementation of this recommendation, the GCR customer is left
6 with the choice of knowing that while the GCR factor in April and May 2006 is
7 \$9.3196/Mcf, the gas company that increased their gas bill dramatically over the
8 past two years may charge them up to \$14.30/Mcf – an amount that is out of line
9 with current market conditions. Even the customers who realize the Company
10 was not to blame for the price increases may decide that a guarantee of \$11.50 is
11 better than the risk of \$14.30/Mcf.

12 The only way to insure a relatively level playing field for the GCR program and
13 the GCC program is to set a new base GCR ceiling price in conjunction with an
14 appropriate CM. Otherwise, the base GCR ceiling factor filed by the Company
15 will send incorrect price signals to the GCR customers and distort the choice they
16 are making between GCR service and signing up with an alternative gas supplier.

17 In a period of relatively high natural gas prices, making the wrong choice will
18 undoubtedly cause financial harm to many customers.

19 **Q. DO YOU HAVE OTHER RECOMMENDATIONS WITH RESPECT TO**
20 **MGU'S CM?**

21 **A.** Yes. I recommend two additional changes to the CM.

22 First, if my recommendation to set the base ceiling GCR factor at \$9.3196/Mcf is

1 adopted, the quarterly GCR Factor Ceiling Price Contingency Matrix shown on
2 Exhibit A-11 should be adjusted to reflect this price change. Specifically, the
3 “Plan NYMEX” numbers that appear in the second row of that exhibit should be
4 reduced to reflect the change to the Company’s original price projections.

5 Second, I disagree with the use of the recommended CM because it is too
6 complex. In developing its GCR Plan, the Company did not itself attempt to
7 formulate a CM. Instead, MGU’s Exhibit A-11 duplicates Staff’s Exhibit S-1
8 from Case No.

9 U-14400 except for the lines “Plan NYMEX” and “Base GCR Factor”.

10 However, MGU did not include an exhibit similar to Staff’s Exhibit S-3 from
11 Case No.

12 U-14400 entitled “Calculation of Fractional Multipliers for Staff Multi-Input
13 Contingent GCR Factor Method” that provides the basis for the numbers in the
14 line labeled “Fractional Mult. F_m ” on Exhibit A-11. These fractional multipliers
15 change from year to year based on the data from Exhibit A-7, page 4. MGU did
16 not perform that calculation in this case. Instead, it simply repeated the fractional
17 multipliers from Case No. U-14400. If the Company does not take the time and
18 effort to develop an accurate Contingent GCR Factor Table, how would MGU
19 explain it to customers?

20 In addition to being overly complex and difficult to explain, I believe that the
21 Staff’s Multi-Input Method that is used by MGU in Exhibit A-11 calculates a
22 degree of precision that is not supported by actual operations, which are subject

1 to actual weather patterns and other variations from the filed plan regarding
2 storage injections and withdrawals. In today's volatile market, the timing of
3 purchases can mean a variance of \$0.00-\$1.00 in spite of the actual NYMEX
4 close in any given month. An example of this would be buying gas for May 2006
5 at the beginning, middle or end of April 2006, as discussed earlier in this
6 testimony.

7 I recommend a simpler, more straightforward approach. Take the average of
8 NYMEX prices to date plus the projected NYMEX price for the remaining
9 months and add a percentage of the difference to the "Plan NYMEX" of \$8.6176
10 per Mcf. For example, if 50% of the gas purchase requirements for the year are
11 purchased in the first six months (April thru September) at approximately \$7.35
12 per Mcf and the NYMEX projection for October thru March is approximately
13 \$9.90 per Mcf, the average price for the year will be approximately \$8.625 per
14 Mcf. If another hurricane occurred and the NYMEX projection for October thru
15 March rose by \$3.00 per Mcf to approximately \$12.90 per Mcf, the average price
16 for the year would be approximately \$10.125 per Mcf. If six DCA purchases had
17 been made at approximately \$10.30 per Mcf, then the NYMEX price increase
18 would be covered with 40% of the NYMEX increase plus the hedge associated
19 with DCA purchases.

20 I am recommending an annual "Plan NYMEX" of \$8.6176 per Mcf with
21 Fractional Multipliers of 100%, 80%, 60% and 40% respectively for each of the
22 four quarters. Percentages are based on known prices for 0, 3, 6, and 9 months

1 respectively. The fourth quarter may seem low until consideration is given to the
2 fact that MGU plans to purchase only 11.6% (after deducting DCA purchases) of
3 its annual requirements from January through March. This has occurred as a
4 result of increased storage from Washington 10 and decreased GCR
5 requirements.

6 I also recommend that symmetry be applied to the Contingency Mechanism with
7 a floor at the Base GCR Factor of \$9.3196.

8 If the Commission does not accept my recommendation to adjust the Base GCR
9 Factor from \$12.2978 per Mcf to \$9.3196 per Mcf, then I recommend removal of
10 any Contingency Mechanism for the 2006-07 Plan year because it will be
11 unnecessary.

12 **Q. DID YOU EXAMINE THE OPERATIONAL AND ESTIMATING**
13 **PROCEDURES PROPOSED BY THE COMPANY?**

14 **A.** Yes. I analyzed the estimates of annual and monthly GCR requirements, Peak
15 Day estimate, planned storage utilization, plan to accommodate colder-than-
16 normal (CTN) weather, utilization of firm transportation available and capacity
17 release credits.

18 **Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF TOTAL GCR**
19 **REQUIREMENTS AND MONTHLY DISTRIBUTION?**

20 **A.** In the past four GCR periods, the Company has over-estimated the monthly
21 requirements for April, May and October by approximately 500 MMcf. The
22 monthly estimates for 2006-2007 are once again high by approximately 150

1 MMcf in April, 100 MMcf in May, and 250 MMcf in October. I am
2 recommending once again that the Company review these months and revise the
3 GCR Plan to reduce the requirements for each of them.

4 In MGU's GCR Reconciliation filings, available on the MPSC's Electronic Case
5 Filings, the monthly GCR Sales are displayed in Exhibit A-4 and the daily degree
6 days (DDD's) are displayed in Exhibit A-3. I recommend that the Company's new
7 management review this data to improve MGU's operations.

8 I believe that the source of this problem is the Company's view, stated in MGU's
9 discovery response 01-RRC-4, that the Use/DDD is a constant instead of a
10 variable in the shoulder months. My analysis was different. It was based on a
11 system-wide base use of 15 MMcf and Use Factors of 2.2 MMcf/DDD in April,
12 1.4 MMcf/DDD in May and 1.7 MMcf/DDD in October.

13 My primary focus was the winter period (November through March) and my
14 analysis produced the same GCR requirement of approximately 16.2 Bcf.

15 However, I recommend that the estimate in MGU's GCR Plan for November be
16 reduced by 200 MMcf and the estimate for January be increased by 200 MMcf.

17 My analysis is based on a system-wide base load of 15 MMcf and use factors in
18 MMcf/DDD of 2.4, 2.8, 2.9, 2.8 and 2.6 for November thru March respectively. I

19 believe the 200 MMcf increase in the estimate for January is important since it
20 represents the equivalent of over 5% colder-than-normal weather.

21 These refinements to MGU's estimates of its GCR requirements and monthly
22 distributions will help optimize the Company's gas supply operations.

1 **Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF MGU’S PEAK**
2 **DAY ESTIMATE?**

3 **A.** The RRC asked MGU several discovery questions pertaining to the peak day
4 estimate in the 2006-2007 GCR Plan. The Company’s responses to discovery
5 questions 01-RRC-02, 01-RRC-05, 01-RRC-08, 01-RRC-09, and 01-RRC-10 by
6 Mr. Stephen R. Larner provided sufficient information to warrant my acceptance
7 of the Peak Day estimate of 224,711 Mcf shown in Exhibit A-4. I would also
8 compliment Mr. Larner on the thoroughness of his responses.

9 **Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF MGU’S**
10 **PLANNED STORAGE UTILIZATION AND PLAN TO ACCOMMODATE**
11 **CTN WEATHER?**

12 **A.** I agree with the Company’s acquisition of Washington 10 storage for the
13 economic benefits associated with summer/winter price differentials. However, I
14 am troubled by the Company’s response to discovery question 01-RRC-11(e)
15 which is included in my testimony as Exhibit RRC-3.
16 The response claims that the second benefit of acquiring Washington 10 storage
17 is operational in nature, and then describes the benefits of ANR storage and/or
18 MGU storage as though this was true for Washington 10 storage. The nature of
19 Washington 10 storage dictates operation of 100% load factor for the period
20 December 1 thru March 31. This is confirmed by multiplying the MDQ of 11,600
21 Dth by the days in the month and comparing the monthly availability to the
22 planned withdrawals on Exhibit A-7 and Mr. Ono’s testimony on Page 11.

1 Therefore, Washington 10 storage is the very same as firm transportation
2 operated at 100% load factor in December thru March and provides none of the
3 operational benefits claimed by the Company in its response. The only exception
4 occurs in the month of November when withdrawals are scheduled at
5 approximately 50%. This can preserve ANR and/or MGU storage for a higher
6 inventory level as of December 1st.

7 The point of my discovery question was to suggest that the Company should place
8 Washington 10 storage on a separate line and not treat it as normal variable
9 storage for operational planning. In the 2003-2004 and 2004-2005 GCR Plan
10 periods, MGU's planned storage inventory as of December 1st was 6.1 Bcf. The
11 Company has now reduced the planned storage inventory for ANR and MGU to
12 5.0 Bcf as of December 1st and shows 1.4 Bcf for Washington 10 storage. For
13 operational planning, the monthly Washington 10 storage should be considered as
14 flowing supply and the December 1st target level for ANR and MGU storage
15 should be approximately 6.0 Bcf to provide a floating reserve of at least 500
16 MMcf to accommodate colder-than-normal (CTN) weather.

17 I recommend that MGU's new management and the Commission review my
18 testimony in Case No. U-13550 on Page 7 thru the top of Page 10. That
19 testimony provided specific operational guidelines under various scenarios
20 including WTN, Normal and CTN weather. In my opinion, the 2006-2007 Plan
21 as filed does not provide any specifics to accommodate variable weather, only
22 generalities and incorrect storage targets for ANR and MGU storage.

1 **Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT MGU’S PLANNED**
2 **STORAGE UTILIZATION?**

3 **A.** Yes. The Company’s filing in Case No. U-13900, the 2004-2005 GCR Plan,
4 showed 40,000/D from MGU storage with storage withdrawals of 3,350,000. The
5 current GCR Plan shows 30,000/D with the same quantity of storage withdrawals.
6 My examination of monthly differences showed that the current plan has 37
7 MMcf less storage withdrawals in April and 263 MMcf less in October with 81
8 MMcf more storage withdrawals in November and December combined, 39
9 MMcf more in January, and 180 MMcf more in February and March combined.
10 The Company’s discovery response 01-RRC-11(d) in this case states that, “In
11 order to cycle more of the capacity of its storage operation, MGU revised its plan
12 to withdraw more volumes in November and December than in past years. This
13 lower inventory level going into January reduces the peak day deliverability to
14 30,000 Dth/Day.” This response is incorrect since it is obvious that the
15 November 1 inventory level is higher by 300 MMcf as of January 1 and 180
16 MMcf higher at the end of January. Either Exhibit A-7 is incorrect or the
17 Company’s discovery response is incorrect. I recommend that the Peak Day
18 supply from MGU storage be restored to the previous level of 40,000 Dth/Day so
19 that the Company can make plans to reduce firm transportation by 10,000
20 Dth/Day.

**Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS REGARDING
UTILIZATION OF FIRM TRANSPORTATION AND CAPACITY
RELEASE CREDITS?**

A. The Company's discovery response 01-RRC-11(f) which is part of Exhibit RRC-3 (FJH-3) confirms that the occurrence of normal weather results in unused firm transportation for January of 14,707 Mcf on ANR SE and 13,222 Mcf on PEPL for a total of 27,929 Mcf which would be required for peak day.

The majority of PEPL supply is associated with a "Winter Only" contract for 32,407 Mcf/D with an annual contract for 13,748 Mcf/D as shown on line 7 of Exhibit A-9. The "Annual Contract" for PEPL supply shown on line 6 of that exhibit is utilized at 100% load factor and the Winter Only contract is cost effective in the event of unused capacity. Of all of MGU's gas supply and transportation contracts, the best candidate for a reduction in firm transportation capacity is ANR SE shown on line 4 of Exhibit A-9. This contract could be reduced by 10,000 Dth/D and be offset by restoring MGU to the previous level of 40,000/D. This would save just over \$1 million in annual demand costs and reduce the amount of daily spot purchases to meet a peak day. Unfortunately, the contract expiration is not until March 2009. Under these circumstances, I recommend that the Company pursue a capacity release on ANR SE on a non-recallable year-to-year basis.

1 **Q. DO YOU HAVE OTHER FINDINGS WITH RESPECT TO MGU'S**
2 **UTILIZATION OF ITS FIRM TRANSPORTATION?**

3 **A.** Yes. The Company's discovery response to 01-RRC-11(g) which is part of
4 Exhibit RRC-3 (FJH-3) confirms that it could be necessary for MGU to buy daily
5 spot gas to meet peak day demand amounting to 10,255 Mcf on CP and 4,937
6 Mcf on MichCon for an additional total of 15,192 Mcf . This is an ideal source
7 of supply since it involves no annual demand charges with a modest
8 transportation charge when utilized.

9 The Company's discovery response 01-RRC-15 which is presented in this
10 testimony as Exhibit RRC-4 (FJH-4) confirms that the firm transportation for
11 flowing gas shown on Exhibit A-9, lines 2-7 results in a 50% load factor for the
12 winter period. Part of this problem was caused by the addition of 11,543 Mcf/D
13 from Washington 10 storage and the reduction of 10,000 Mcf/D from MGU
14 storage. Though these changes were likely connected (versus the Company's
15 representation that it plans to withdraw more from storage in November and
16 December than in past years to cycle more of the capacity of its storage
17 operation), there is no disputing the fact that the current winter/summer price
18 differentials more than offset the cost associated with Washington 10 storage and
19 10,000/D of excess firm transportation.

20 In addition to my recommendation that MGU pursue capacity release until the
21 ANR SE contract can be reduced in March 2009, I recommend that the Company
22 explore the availability of a 10-day peaking service. This type of service is the

1 best answer to the current under-utilization of firm transportation. It is possible
2 that recallable capacity release credits would offset the peaking service expense
3 and make a return for the GCR customers. Even without the acquisition of a
4 peaking service, MGU should vigorously pursue recallable capacity release.
5 There were no capacity release credits shown on Exhibit A-7, page 2, line 25 for
6 any of the 5 years in MGU's GCR Plan. I recommend that in its order in this
7 case, the Commission find that it is reasonable and prudent for MGU to pursue
8 capacity release in the 2006-2007 GCR period and warn the Company that it
9 should continue to pursue capacity release in the four out years of the GCR Plan.

10 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

Michigan Gas Utilities Corporation

Michigan Public Service Commission
Case No. U-14715

Residential Ratepayer Consortium's First Data Request

01-RRC-17

Please respond to the following regarding Mr. Tyler's testimony on GCR factors (Page 6-11):

- h. Explain why the "Probability Weighted Price Risk Factor" is not redundant when coupled with a "NYMEX Futures Update" together with a "Contingent GCR Factor Matrix".
- i. Confirm that the "NYMEX Factors Update" one week prior to the date for Motions to Strike can result in a reduction to the GCR Factor. If not, why not?

Response

- a. Coupling the "Probability Weighted Price Risk Factor" with a "NYMEX Futures Update" would be redundant when developing the "Contingent GCR Factor Matrix", that is why at page 11, lines 5 through 13, I specifically state that the Company does not intend to incorporate the "Probability Weighted Price Risk" component into its "Contingent GCR Factor Matrix". The "Probability Weighted Price Risk Factor" is only utilized for the establishment of the GCR Ceiling factor in the Company's initial filing.
- b. The NYMEX Factors Update could support a revision. However, such a revision would not result in a GCR factor lower than the "Base GCR Factor" established in the Contingent Matrix.

Answered by: David J. Tyler

Dated: May 12, 2006

Michigan Gas Utilities Corporation

Michigan Public Service Commission
Case No. U-14715

Residential Ratepayer Consortium 1st Data Request

01-RRC-18 On page 18, lines 8-10 of his testimony, Mr. Ono describes the six-step process the Company uses to develop its pricing assumptions.

- a. Please provide the data shown on Exhibit A-6, Page 1 using the average NYMEX prices for the twelve months beginning April 1, 2006 for the first five trading days in April.
- b. Please quantify how using the average NYMEX prices for the twelve months beginning April 1, 2006 for the first five trading days in April 2006 changes the Total 2006/2007 Projected Gas Costs shown on line 25 of Exhibit A-2, page 4.
- c. Please identify any changes that have occurred since December 2005 that affect the accuracy of the data referenced in Step #2 through Step #6 on page 18, line 11 through page 19, line 2 of Mr. Ono's testimony.
- d. For any change(s) identified in response to the preceding question, please quantify the impact(s) on the cost projections contained in Aquila's 2006-2007 GCR Plan.

Response:

- a. Please see Attachment 01-RRC-18.
- b. Utilizing the average NYMEX prices for the twelve months beginning April 1, 2006 for the first five trading days in April 2006 reduces the Total 2006/2007 Projected Gas Cost shown on line 25 of Exhibit A-2, page 4, by \$65,356,924 to \$246,368,882.
- c. The underlying methodology remains intact. Price volatility has impacted basis differentials for the various supply basins referenced in Step #3. This, in turn, has had an impact on the projected "into the pipe or city gate" price. Step #4 remains virtually unchanged. Fuel costs have moved in conjunction with said volatility. Consequently, the delivered city gate price referred to in Step #6 has changed proportionately to the changes in prices.
- d. The aggregate impact of the changes referred to above has the net effect of reducing the GCR Factor. Using the average in NYMEX prices for the twelve months beginning April 1, 2006 for the first five trading days in April 2006 reduced the GCR Factor from \$12.2978 per Mcf in the original Exhibit A-7, Page 2 of 23, to \$9.3904 per Mcf, a reduction of \$2.9074 per Mcf. The Company does not, however, agree that the NYMEX futures settlement

the current or future natural gas futures market prices. For instance, utilizing the NYMEX Futures 5-day average pricing outlined in 01-RRC-16 yields a GCR Factor of \$10.3697, an intra-month change of +\$0.9757. Price volatility, and its associated impact on the GCR Factor, will continue for the foreseeable future. High national storage inventories are pressing prices lower while higher oil prices and projections of a hurricane season equal to last year's press prices higher.

Answered by: Kent E. Huzzey

Dated: May 12, 2006

LALIB:141650.1\131120-00002

MICHIGAN PUBLIC SERVICE COMMISSION
MICHIGAN GAS UTILITIES

ATTACHMENT
01-RRC-16

SUMMARY OF 2006 - 2011 COST OF GAS
Residential Ratepayer Consortium's 1st Data Request (01-RRC-16)
Dates utilized included the April Settle on March 29 as well as April 18, 19, 20 and 21

Line	Description	2006	2007	2008	2009	2010
<u>Commodity Costs</u>						
1	ANR ETS - Southeast	\$22,193,537	\$40,995,304	\$43,657,393	\$50,152,174	\$60,117,266
2	ANR - ML7	\$28,416,439	\$26,658,998	\$26,975,465	\$25,011,467	\$24,836,168
3	ANR ETS - Southwest	\$17,413,980	\$22,858,443	\$23,673,032	\$24,309,059	\$25,066,304
4	ANR ETS - Canadian	\$25,021,251	\$30,078,995	\$30,985,393	\$31,918,984	\$32,879,131
5	Panhandle EFT	\$74,344,378	\$88,098,182	\$92,025,753	\$96,077,393	\$95,358,692
6	Panhandle Market Zone	\$0	\$0	\$0	\$0	\$0
7	MichCon	\$13,910,723	\$18,595,148	\$19,139,074	\$19,699,318	\$20,274,560
8	Consumers Power	\$32,345,355	\$39,309,192	\$40,721,901	\$41,862,289	\$43,088,089
9	Union	\$0	\$0	\$0	\$0	\$0
10	Production	\$6,252,511	\$7,412,230	\$7,604,381	\$7,854,898	\$8,058,464
11	Authorized Overrun Charges	\$89,560	\$89,560	\$89,560	\$89,560	\$89,560
12	Daily Scheduling Charges	\$0	\$0	\$0	\$0	\$0
13	Other Commodity Charges	\$98,676	\$98,676	\$98,676	\$98,676	\$98,674
14	Total Suppliers	\$220,086,390	\$273,194,727	\$284,870,829	\$297,073,828	\$309,866,907
<u>Pipeline Demand/Supply Reservation Costs</u>						
15	ANR Enhanced Transportation Service,(ETS)	\$3,210,932	\$3,457,514	\$3,457,514	\$3,457,514	\$3,457,514
16	PEPL Enhanced Firm Transportation (EFT)	\$3,720,256	\$3,420,831	\$3,420,831	\$3,420,831	\$3,420,831
17	Trunkline Firm Transportation (FT)	\$0	\$0	\$0	\$0	\$0
18	Mich Con Wash 10 Storage Service	\$735,024	\$735,024	\$735,024	\$735,024	\$735,024
19	ANR No-Notice Service (NNS)	\$906,250	\$906,250	\$906,250	\$906,250	\$906,250
20	ANR Firm Storage Service-(FSS)	\$2,473,452	\$2,473,452	\$2,473,452	\$2,473,452	\$2,473,452
21	ANR Supply Reservation Charges	\$0	\$0	\$0	\$0	\$0
22	ANR ETS - Between MGU & ANR FSS Storage	\$1,809,680	\$1,609,680	\$1,609,680	\$1,609,680	\$1,609,680
23	PEPL Reservation Costs	\$0	\$0	\$0	\$0	\$0
24	PEPL GDS Demand	\$0	\$0	\$0	\$0	\$0
25	Capacity Release Credits	\$0	\$0	\$0	\$0	\$0
26	Total	\$12,655,594	\$12,602,751	\$12,602,751	\$12,602,751	\$12,602,751
27	Total Purchased and Produced	\$232,741,984	\$285,797,478	\$297,473,380	\$309,676,579	\$322,469,658
28	Net (To)/From Storage	\$376,610	\$4,926,823	\$5,233,442	\$5,549,259	\$6,106,801
29	Total Cost of Gas	\$233,118,594	\$290,724,301	\$302,706,821	\$315,225,838	\$328,576,458
30	2005 Projected (Over) Recovery	(\$13,346)	\$0	\$0	\$0	\$0
31	Total Projected 2006- 2011 GCR Costs	\$233,105,248	\$289,094,294	\$301,076,814	\$313,595,831	\$326,946,451
32	Total GCR Supply	22,479,400	22,750,000	23,025,800	23,306,300	23,592,300
33	GCR Factor	\$10.3697	\$12.3601	\$12.8724	\$13.4076	\$13.9784
36	Demand Component	\$0.5630	\$0.5388	\$0.5388	\$0.5388	\$0.5388
37	Commodity Component	\$9.7906	\$11.6803	\$12.1795	\$12.7012	\$13.2482

Michigan Gas Utilities Corporation

Michigan Public Service Commission
Case No. U-14715

Residential Ratepayer Consortium's First Data Request

01-RRC-11 Please Refer to Exhibit A-9 and answer the following:

- a. Should line 1 be eliminated and has it been replaced by line 2?
- b. Has the contract for line 5 been extended? If so, what is the new data and why is it not included on Exhibit A-7? If not, what is the replacement for the 10,000 Dth in the MDAQ?
- c. Confirm that the contract for line 13 has been extended and provide the new term dates.
- d. Please explain why the daily availability from MGU storage on a peak day has been reduced from 40,000 Dth/Day (2004 and earlier) to 30,000 Dth/Day.
- e.
 - i. Other than possible summer/winter price differentials, please explain how Washington 10 storage is any different from firm transportation operated at 100% load factor in December thru March and how this storage would reduce daily spot purchases.
 - ii. Also, please explain the \$7.02 demand charge and how this relates to \$735,024 of total demand costs on Exhibit A-7, Page 2, line 18.
- f. Please confirm that comparing Exhibit A-7 to Exhibit A-9 results in unused firm transportation for January of 14,707 Mcf on ANR SE and 13,222 Mcf on PEPL.
- g. In addition to daily spot purchases of 27,929 Mcf in the above question, please confirm that it would be necessary to buy daily spot gas amounting to 10,255 Mcf on CP and 4,937 Mcf on MichCon for a total daily spot purchase of 43,121 Mcf plus 9,788 Mcf on ANR ML-7 at daily index in order to meet a peak day.

Response:

- a. Yes, line 1 was displayed to show the expiring contract and its replacement.
- b. Yes it goes to March 31, 2007. Please see Revised Exhibit A-9; A copy is attached as Attachment 01-RRC-11.
- c. Yes it goes to March 31, 2008. Please see Revised Exhibit A-9.
- d. The maximum deliverability for MGU storage is still 40,000 Dth/day. However, in

withdraw more volumes in November and December than in past years. This lower inventory level going into January reduces the peak day deliverability to 30,000 Dth/day.

- e. i. One benefit, as alluded to in the question, is capitalizing on the Summer/Winter spread. Based on the NYMEX settlement for 8 May 2006, the Winter/Summer spread is \$3.54/dt. This represents a significant price differential benefit. The second benefit is operational in nature. Storage provides substantial, daily volumetric swing in the market area. Firm transportation, operated at 100% load factors, lacks this operational swing. Additionally, pipelines are very reluctant, at this time, to enter into seasonal transportation from the Mid-continent. The ability to pull storage when needed mitigates the need to buy in the daily spot market thus reducing exposure to price spikes.
- ii. The demand rate of \$7.02 includes transportation, storage capacity and storage deliverability. This was posted in this fashion to show all charges associated with Wash 10 storage. The break out is as follows

Deliverability - $\$2.4037 * 11,600$ per month = \$27,882.92 per month
Capacity - $\$.021 * 1,589,000$ per month = \$33,369.00 per month
Mich Con Transportation - \$1.74 monthly demand rate.
- f. Yes, under normal weather conditions the volumes cited would be unutilized. The incremental capacity is contracted for to insure that peak day loads are adequately covered.
- g. Possibly yes, but MGU has successfully utilized Deferred Delivery Service from ANR for the past two years. This has allowed the Company to effectively increase its ability to withdraw additional supply over firm entitlement levels from storage in order to minimize any daily purchases that may be required above first of the month supplies and firm storage withdrawal capabilities.

Answered by: Kent E. Huzzey

Dated: May 12, 2006

Exhibit RRC-3 (FJH-3)
MPSC Case No. U-14715
Page 3 of 3

REVISED

ATTACHMENT
01-RRC-11

MICHIGAN GAS UTILITIES
SUMMARY OF GAS SUPPLY AND TRANSPORTATION CONTRACTS

Case No. U-14715
Exhibit A-9 Page 1 of 3
Witness Kent E. Huzzey

MICHIGAN GAS UTILITIES							
SUMMARY OF GAS SUPPLY AND TRANSPORTATION CONTRACTS							
		MCF	DTH				
1	ANR ETS - CANADIAN #109418	6,852	7,000	2,128,000	11/93 - 10/05	\$11.2444 x MDQ	\$0.02
2	ANR ETS - Co Energy (Chicago)	6,852	7,000	2,555,000	11/05 - 3/08	\$4.2888 x MDQ	
3	ANR ETS - SOUTHWEST #109422	6,852	7,000	1,486,000	4/04 - 3/09	\$9.8187x MDQ	\$0.02
4	ANR ETS - SOUTHEAST #110024	25,734	28,291	3,830,000	4/04 - 3/09	\$8.396 x MDQ	\$0.02
5	ANR ML-7 (NEXEN)	9,788	10,000	151,000	11/1/05-3/31/07	\$3.3482 x MDQ	\$0.02
6	PANHANDLE - EFT (Annual) #018328/#17000	13,748	14,000	3,285,000	11/02 - 3/08	\$8.1581 x MDQ	\$0.049
7	PANHANDLE - EFT (Winter Only) #17000	32,407	33,000	4,983,000	11/02 - 3/08	\$8.1581 x MDQ	\$0.049
8	CONSUMERS POWER #003	19,240	19,445	0	Evergreen	Month to Month	\$0.12
9	CONSUMERS POWER - Balancing #003	2,450	2,560	250000	Month to Month	Month to Month	\$0.12
10	MICHCON #032	4,837	5,000	0	Month to Month	Month to Month	0.1
11	ANR STORAGE - ANNUAL #110019,110020,110	61,986	63,308	3,182,850	4/04 - 3/09	\$2.45 x ACQ capacity only	\$0.01
12	WASHINGTON 10 STORAGE	11,453	11,800	1,589,000	5/04-4/07	\$7.02 (includes transport)	
13	STORAGE (Redelivery via PEPL ONLY, from MGU Storage #17684	14,730	15,000		11/02 - 3/08	\$1.6731 x 15000 MDQ PEPL	100% Load Factor
14	MGU STORAGE	14,702	15,000	3,600,000			
15	TOTAL MDQ	224,711	229,204				

Michigan Gas Utilities Corporation

Michigan Public Service Commission
Case No. U-14715

Residential Ratepayer Consortium First Data Request

01-RRC-15 Assuming that line 1 on Exhibit A-9 has expired, the total MDQ of lines 2-7 is 95,381 Mcf which would result in 14,402,531 Mcf during November thru March at 100% load factor. The actual utilization shown on Exhibit A-7 amounts to 7,235,791 or a 50% load factor. Please confirm the preceding and explain why a 50% load factor should be acceptable.

Response: Yes, you are correct. The plan calls for capacity utilization of approximately 50%. This is needed to cover the swings in heating load primarily from residential customers. MGU does not manage a significant industrial load. Industrial loads can be closer to a 100% load factor. MGU's load is primarily residential, multi family, and small commercial customers that have an annual load factor of approximately 25% or lower. They are highly heat sensitive. The additional capacity is needed to cover peak day conditions. In addition the pipelines that serve MGU do not sell monthly capacity. MGU can only buy annual or winter service. The capacity purchases can't be shaped to a monthly or daily perspective.

Answered by: Kent E. Huzzey

Dated: May 12, 2006

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of AQUILA NETWORKS-)	
MGU for authority to implement a gas cost recovery)	
Plan and factors for the 12-month period ending)	Case No. U-14715
March 31, 2007.)	
_____)	

PROOF OF SERVICE

The undersigned certifies that on Thursday, May 25, 2006 he served a copy of the
Testimony and Exhibits of Frank J. Hollewa on Behalf of the Residential Ratepayer Consortium on the parties listed below by electronic mail at each of their e-mail addresses shown below.

David L. Shaltz

Digitally signed by David L. Shaltz
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