EEP-2013-0001

FILED WITH
Executive Secretary

March 29, 2013

IOWA UTILITIES BOARD

Black Hills Energy

Natural Gas
Energy-Efficiency Plan
2014-2018:

Appendices E-H

Prepared for:
Iowa Utilities Board

Docket EEP-2013-0001

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Appendix E. Gas Forecasts

ENERGY EFFICIENCY PLAN

DOCKET NO. EEP-08-

Five-Year Forecast

March 15, 2013

Black Hills Energy-Iowa

ENERGY EFFICIENY PLAN 2013 FORECAST

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INTRODUCTION

Iowa Administrative Code 199--35.11 provides, in part, that:

> ..."In those years a gas utility does not file an energy efficiency plan, the utility shall file by November 1 the information required in subrule 35.10(1). If there has been no change in the information required in paragraphs 35.10(1)"f" through "h", the utility shall identify the portions of the previous docket where the information is located."

Black Hills Energy submits the following forecast in compliance with the aforementioned rule.

STATEMENT IN NUMERICAL TERMS OF THE UTILITY'S CURRENT 12-MONTH AND 5-YEAR FORECASTS OF

TOTAL ANNUAL THROUGHPUT AND PEAK DAY DEMAND

Iowa Administrative Code: 35.10(1) "a"

Annual Throughput and Peak Day

Demand Forecast by Customer Class

Total annual throughput forecast and peak day demand forecast by for the Black Hills-IA natural gas service area in Iowa are shown Table 1 by customer class.

Projections of throughput are based on normalized weather over a 30-year period 1981-2010 currently used by the National Oceanic and Atmospheric Administration for Dubuque, IA ("DBQ"). Peak day demand estimates are based on the peak weather experienced in the last twenty years for Council Bluffs, IA ("CBF"), Des Moines, IA ("DSM"), Dubuque, IA ("DBQ"), and Spencer, IA ("SPW").

As a result, projections of throughput and peak day demand do not reflect recent historical weather or forecasts of future weather.

TABLE 1A

5-Year Throughput and Peak Day Forecasts (Mcf)

Black Hills- IA Gas: 5-Year Forecast Class Sales Throughput and Peak Day Demand (MCF)

(1)	(2)	(3)	(4)
Forecast MCF	Class	Peak Day Demand	Total Annual Thruput
2013			
FIRM SALES:	Residential	110,367	10,191,378
	Commercial	58,194	5,368,593
	Industrial	3,211	304,031
INTERRUPTIBLE SALES:	Commercial	6,279	577,088
	Industrial	16,483	1,576,844
Other Sales:	Other	392	52,071
TRANSPORATION:		68,350	19,041,288
TOTAL		263,064	37,111,293
2014			
FIRM SALES:	Residential	109,322	10,140,094
	Commercial	57,643	5,368,593
	Industrial	3,180	304,031
INTERRUPTIBLE SALES:	Commercial	6,220	577,088
	Industrial	16,327	1,276,844
Other Sales:	Other	389	52,071
TRANSPORATION:		67,703	19,041,288
TOTAL		260,784	36,760,009
2015			
FIRM SALES:	Residential	109,171	10,089,070
	Commercial	57,563	5,368,593
	Industrial	3,176	304,031
INTERRUPTIBLE SALES:	Commercial	6,211	577,088
	Industrial	16,305	1,276,844
Other Sales:	Other	388	52,071
TRANSPORATION:		67,609	19,041,288
TOTAL		260,422	36,708,984
2016			
FIRM SALES:	Residential	109,020	10,038,303
	Commercial	57,483	5,368,593
	Industrial	3,171	304,031
INTERRUPTIBLE SALES:	Commercial	6,203	577,088
	Industrial	16,282	1,276,844
Other Sales:	Other	388	52,071
TRANSPORATION:		67,516	19,041,288
TOTAL		260,062	36,658,217
2017			
FIRM SALES:	Residential	108,869	9,987,792
	Commercial	57,404	5,368,593
	Industrial	3,167	304,031
INTERRUPTIBLE SALES:	Commercial	6,194	577,088
	Industrial	16,260	1,276,844
Other Sales:	Other	387	52,071
TRANSPORATION:		67,423	19,041,288
TOTAL		259,704	36,607,707

TABLE 1B

Current 12-Month Throughput and Peak Day Forecast (MMcf)

Black Hills- IA Gas: 5-Year Forecast Class Sales Throughput and Peak Day Demand (MCF)

1	2	3	4	5	6	7	8	9	10	11	12
MMcf	n_HDD (DBQ)	ResCust	MCF ResUPC	ResSales	ComSales	IndSales	OthSales	TotalSales	Transport	Thruput	PeakDay
2013.01	1,423	136,459	14.4	1,959.6	1,060.7	160.1	9.1	3,189.5	1,851.7	5,041.1	263.3
2013.02	1,192	136,692	13.2	1,800.5	966.7	114.1	10.5	2,891.7	1,811.3	4,703.1	238.7
2013.03	918	136,941	10.7	1,464.7	805.0	136.2	7.8	2,413.7	1,525.3	3,939.0	199.2
2013.04	510	136,775	3.7	501.2	308.8	106.3	3.3	919.6	1,307.2	2,226.7	75.9
2013.05	225	136,254	3.0	404.8	292.2	107.1	2.1	806.3	1,700.2	2,506.5	66.6
2013.06	40	135,876	1.4	188.4	199.8	100.4	2.1	490.6	1,485.0	1,975.6	40.5
2013.07	0	135,156	0.6	80.3	75.6	97.9	1.2	255.0	1,483.8	1,738.8	21.1
2013.08	16	135,061	1.9	254.1	219.8	160.7	1.1	635.7	1,524.4	2,160.1	52.5
2013.09	152	134,851	0.9	120.2	147.6	166.0	1.4	435.1	1,627.1	2,062.2	35.9
2013.1	471	135,351	5.1	697.0	613.3	277.5	1.9	1,589.7	1,202.6	2,792.3	131.2
2013.11	850	136,153	6.9	943.9	431.3	195.9	4.2	1,575.3	1,635.8	3,211.0	130.0
2013.12	1,312	136,946	13.0	1,776.7	824.9	258.7	7.5	2,867.8	1,887.0	4,754.8	236.7
2014.01	1,423	137,139	14.2	1,949.7	1,060.7	160.1	9.1	3,179.6	1,851.7	5,031.3	260.8
2014.02	1,192	137,373	13.0	1,791.4	966.7	114.1	10.5	2,882.7	1,811.3	4,694.0	236.4
2014.03	918	137,624	10.6	1,457.4	805.0	136.2	7.8	2,406.4	1,525.3	3,931.6	197.4
2014.04	510	137,457	3.6	498.7	308.8	106.3	3.3	917.0	1,307.2	2,224.2	75.2
2014.05	225	136,933	2.9	402.8	292.2	107.1	2.1	804.2	1,700.2	2,504.4	66.0
2014.06	40	136,553	1.4	187.4	199.8	100.4	2.1	489.7	1,485.0	1,974.7	40.2
2014.07	0	135,830	0.6	79.9	75.6	97.9	1.2	254.6	1,483.8	1,738.4	20.9
2014.08	16	135,734	1.9	252.9	219.8	60.7	1.1	534.4	1,524.4	2,058.8	43.8
2014.09	152	135,523	0.9	119.6	147.6	66.0	1.4	334.5	1,627.1	1,961.6	27.4
2014.1	471	136,026	5.1	693.5	613.3	277.5	1.9	1,586.2	1,202.6	2,788.8	130.1
2014.11	850	136,832	6.9	939.1	431.3	195.9	4.2	1,570.5	1,635.8	3,206.3	128.8
2014.12	1,312	137,629	12.8	1,767.8	824.9	158.7	7.5	2,758.9	1,887.0	4,645.9	226.3
2015.01	1,423	137,822	14.1	1,939.9	1,060.7	160.1	9.1	3,169.8	1,851.7	5,021.5	260.4
2015.02	1,192	138,058	12.9	1,782.4	966.7	114.1	10.5	2,873.7	1,811.3	4,685.0	236.1
2015.03	918	138,310	10.5	1,450.0	805.0	136.2	7.8	2,399.0	1,525.3	3,924.3	197.1
2015.04	510	138,142	3.6	496.2	308.8	106.3	3.3	914.5	1,307.2	2,221.7	75.1
2015.05	225	137,615	2.9	400.7	292.2	107.1	2.1	802.2	1,700.2	2,502.4	65.9
2015.06	40	137,234	1.4	186.5	199.8	100.4	2.1	488.8	1,485.0	1,973.7	40.2
2015.07	0	136,507	0.6	79.5	75.6	97.9	1.2	254.2	1,483.8	1,738.0	20.9
2015.08	16	136,410	1.8	251.6	219.8	60.7	1.1	533.2	1,524.4	2,057.5	43.8
2015.09	152	136,198	0.9	119.0	147.6	66.0	1.4	333.9	1,627.1	1,961.0	27.4
2015.1	471	136,704	5.0	690.0	613.3	277.5	1.9	1,582.7	1,202.6	2,785.3	130.0
2015.11	850	137,514	6.8	934.4	431.3	195.9	4.2	1,565.8	1,635.8	3,201.6	128.6
2015.12	1,312	138,315	12.7	1,758.9	824.9	158.7	7.5	2,750.0	1,887.0	4,637.0	225.9
2016.01	1,423	138,509	13.9	1,930.2	1,060.7	160.1	9.1	3,160.0	1,851.7	5,011.7	260.1
2016.02	1,192	138,746	12.8	1,773.4	966.7	114.1	10.5	2,864.7	1,811.3	4,676.0	235.8
2016.03	918	138,999	10.4	1,442.7	805.0	136.2	7.8	2,391.7	1,525.3	3,917.0	196.8
2016.04	510	138,831	3.6	493.7	308.8	106.3	3.3	912.0	1,307.2	2,219.2	75.1
2016.05	225	138,301	2.9	398.7	292.2	107.1	2.1	800.2	1,700.2	2,500.4	65.9
2016.06	40	137,918	1.3	185.6	199.8	100.4	2.1	487.8	1,485.0	1,972.8	40.1
2016.07	0	137,187	0.6	79.1	75.6	97.9	1.2	253.8	1,483.8	1,737.6	20.9
2016.08	16	137,090	1.8	250.3	219.8	60.7	1.1	531.9	1,524.4	2,056.3	43.8
2016.09	152	136,877	0.9	118.4	147.6	66.0	1.4	333.3	1,627.1	1,960.4	27.4
2016.1	471	137,385	5.0	686.5	613.3	277.5	1.9	1,579.2	1,202.6	2,781.8	130.0
2016.11	850	138,199	6.7	929.7	431.3	195.9	4.2	1,561.1	1,635.8	3,196.9	128.5
2016.12	1,312	139,004	12.6	1,750.0	824.9	158.7	7.5	2,741.1	1,887.0	4,628.1	225.6
2017.01	1,423	139,200	13.8	1,920.5	1,060.7	160.1	9.1	3,150.3	1,851.7	5,002.0	259.7
2017.02	1,192	139,438	12.6	1,764.5	966.7	114.1	10.5	2,855.8	1,811.3	4,667.1	235.4
2017.03	918	139,692	10.3	1,435.5	805.0	136.2	7.8	2,384.5	1,525.3	3,909.8	196.6
2017.04	510	139,523	3.5	491.2	308.8	106.3	3.3	909.5	1,307.2	2,216.7	75.0
2017.05	225	138,991	2.9	396.7	292.2	107.1	2.1	798.2	1,700.2	2,498.4	65.8
2017.06	40	138,605	1.3	184.6	199.8	100.4	2.1	486.9	1,485.0	1,971.9	40.1
2017.07	0	137,871	0.6	78.7	75.6	97.9	1.2	253.4	1,483.8	1,737.2	20.9
2017.08	16	137,774	1.8	249.1	219.8	60.7	1.1	530.6	1,524.4	2,055.0	43.7
2017.09	152	137,559	0.9	117.8	147.6	66.0	1.4	332.7	1,627.1	1,959.8	27.4
2017.1	471	138,070	4.9	683.1	613.3	277.5	1.9	1,575.8	1,202.6	2,778.4	129.9
2017.11	850	138,888	6.7	925.0	431.3	195.9	4.2	1,556.4	1,635.8	3,192.2	128.3
2017.12	1,312	139,697	12.5	1,741.2	824.9	158.7	7.5	2,732.3	1,887.0	4,619.3	225.2
2013	7,109	136,043	74.6	849	495	157	4	1,506	1,587	3,093	124
2014	7,109	136,100	74.5	848	495	157	4	1,505	1,587	3,092	135
2015	7,109	137,402	73.2	841	495	132	4	1,472	1,587	3,059	121
2016	7,109	138,087	72.4	837	495	132	4	1,468	1,587	3,055	121
2017	7,109	138,775	71.7	832	495	132	4	1,464	1,587	3,051	121
%/Year	**0.0%**	**0.5%**	**-1.0%**	**-0.5%**	**0.0%**	**0.0%**	**0.0%**	**-0.3%**	**0.0%**	**-0.1%**	**-0.1%**

Effects of Conservation (Energy-Efficiency)

Conservation (energy-efficiency) impacts on sales are reflected by the declining annual usage per customer (UPC) that Black Hills-IA natural gas has experienced historically, and as projected for the next five years. Residential weather-normal usage per customer ("UPC") is projected to decline at about -1% annually over the 2013-2017 forecast period without future impacts of energy-efficiency programs. Residential UPC is modeled statistically, based on monthly actual UPC explained by weather and historical trends. Over the 2009-2012 historical period, the declining residential UPC trend of -1% annually becomes evident as shown in Chart 1. For commercial, industrial, and transportation classes, growth trends in sales volumes (Chart 2) are affected by Black Hills-IA real GSP, natural gas prices, and customer class migration. Some of the commercial and industrial customers which migrate between classes may remain with Black Hills-IA as transportation customers.

Chart 1

Black Hills-IA: Residential UPC (Mcf per Customer)

Year	ResUPC	ResCust	ResMMcf
2009	79	132,745	10,976
2010	76	133,392	10,082
2011	76	134,059	10,162
2012	75	134,729	10,110
2013	75	136,043	10,191
2014	74	136,721	10,140
2015	73	137,402	10,089
2016	72	138,087	10,038
2017	72	138,775	9,988
CAGR:			
2008-2012	-1.8%	0.5%	-2.6%
2013-2017	-1.0%	0.5%	-0.5%

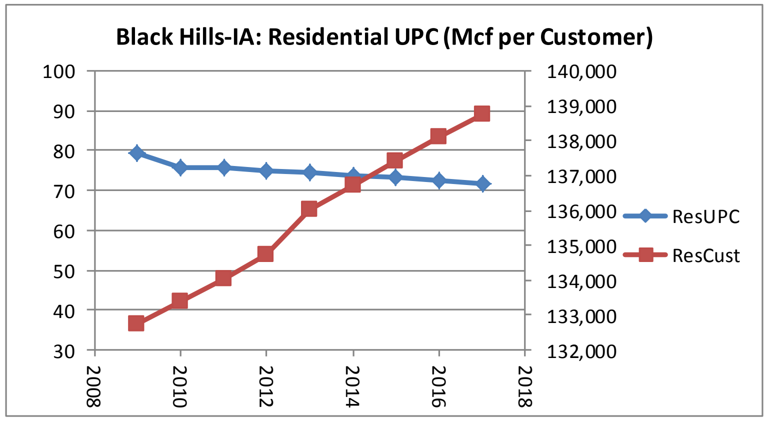
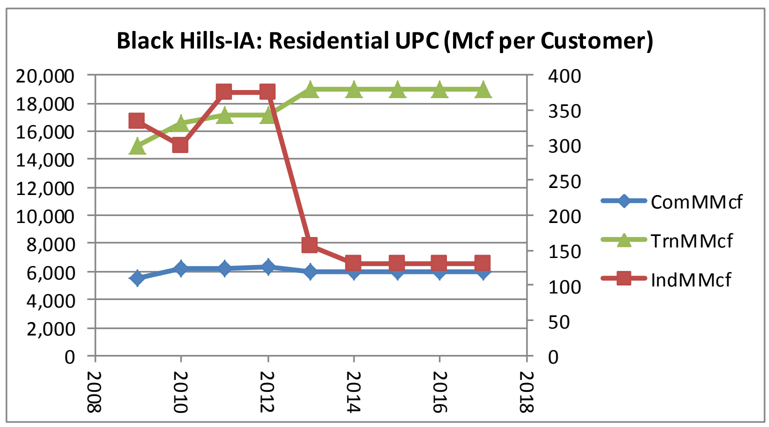


Chart 2

Black Hills-IA: Commercial, Industrial, Transportation (MMcf)

Year	ComMMcf	IndMMcf	TrnMMcf
2009	5,474	333	14,916
2010	6,154	300	16,600
2011	6,240	374	17,101
2012	6,271	374	17,101
2013	5,946	157	19,041
2014	5,946	132	19,041
2015	5,946	132	19,041
2016	5,946	132	19,041
2017	5,946	132	19,041
CAGR:			
2008-2012	4.77%	4.92%	4.77%
2013-2017	0%	-3.99%	0%



Reserve Margin

The following reflects Black Hills-IA natural gas reserve margin based on historical maximum peak days for NNG and NGPL pipelines for the past five years:

Pipeline: Northern Natural Gas (NNG)

Historical Peak and Current Peak Day (million Btu/day)		
Dates of historic peaks	1/15/2009	1/19/2012
Actual Volumes	230,256	199,624
Firm Entitlement (Jan-Mar)	195,922	188,574
Difference	34,334	11,050
Reserve Margin	17.5%	5.9%

Pipeline: Natural Gas Pipeline (NGPL)

Historical Peak and Current Peak Day (million Btu/day)		
Dates of historic peaks	1/4/2010	1/19/2012
Actual Volumes	3,251	2,719
Firm Entitlement (Jan-Mar)	2,900	2,900
Difference	351	-181
Reserve Margin	12.1%	-6.2%

Black Hills-IA Reserve Margin (NNG and NGPL)

Historical Peak and Current Peak Day (million Btu/day)		
Dates of historic peaks	1/15/2009	1/19/2012
Actual Volumes	233,262	202,343
Firm Entitlement (Jan-Mar)	198,822	191,474
Difference	34,440	10,869
Reserve Margin	17.3%	5.7%

See Table 6 later in report for NNG and NGPL pipeline Firm entitlements by month and by contract for 2008-2012 historical period.

HIGHEST PEAK DAY DEMAND AND
ANNUAL THROUGHPUT FOR THE PAST FIVE YEARS
<u>BY CUSTOMER CLASS</u>

Iowa Administrative Code: 35.10(1)"b"

Table 2 provides the highest actual peak day and annual throughput for the most recent 5-year period (2008-2012), and current 12-month forecasts for Black Hills-IA natural gas customers by pipeline by customer class.

TABLE 2

Highest Actual Peak Day and Annual Throughput for Most Recent 5-Year Period

Black Hills-IA Gas: 5-Year Historical Highest Actual Peak Day and Annual Throughput (MCF)

1	2	3	4	5	6	7
Actual MCF	Annual Sales(a)	Highest Peak Day (b)	Annual Throughput (c)	Class	Sales by Class Billed	Transport by Class Billed
2008		12/21/2008: -6F				
Northern Natural gas (NNG)	18,206,221	212,407	30,821,712	Residential	11,551,369	
Natural Gas Pipeline (NGPL)	240,695	3,280	332,623	Commercial	6,539,250	3,097,312
				Industrial	282,447	9,610,107
				Other	37,850	
TOTAL	18,446,916	215,687	31,154,335	TOTAL	18,446,915	12,707,419
2009		1/15/2009: -19F				
Northern Natural gas (NNG)	17,916,845	230,256	32,739,934	Residential	11,073,725	
Natural Gas Pipeline (NGPL)	232,611	3,006	325,123	Commercial	6,681,805	2,753,448
				Industrial	325,635	12,162,153
				Other	68,290	
TOTAL	18,149,456	233,262	33,065,057	TOTAL	18,149,456	14,915,601
2010		1/4/2010: 4F				
Northern Natural gas (NNG)	16,779,921	217,437	34,125,218	Residential	10,556,044	
Natural Gas Pipeline (NGPL)	261,816	3,251	339,043	Commercial	6,061,953	2,748,466
				Industrial	354,436	14,674,058
				Other	69,304	
TOTAL	17,041,737	220,688	34,464,261	TOTAL	17,041,737	17,422,524
2011		2/2/2011: 24F				
Northern Natural gas (NNG)	16,829,481	208,655	35,103,698	Residential	10,490,129	
Natural Gas Pipeline (NGPL)	262,539	3,146	347,014	Commercial	6,125,293	2,952,750
				Industrial	409,723	15,405,942
				Other	66,875	
TOTAL	17,092,020	211,801	35,450,712	TOTAL	17,092,020	18,358,692
2012		1/19/2012: 0F				
Northern Natural gas (NNG)	14,276,914	199,624	32,495,549	Residential	8,732,301	
Natural Gas Pipeline (NGPL)	252,182	2,719	327,774	Commercial	5,249,765	2,771,311
				Industrial	492,633	15,522,916
				Other	54,397	
TOTAL	14,529,096	202,343	32,823,323	0	14,529,096	18,294,227

(a) FERC Form 2, pages 513-514, Sales of Gas (Annual Class Sales by Pipeline)

(b) FERC Form 2, page 516, Distribution System Peak Deliveries (Highest Peak Day), includes transportation.

(c) Annual Throughput (Sales and Transportation, combined).

COMPARISON OF THE FORECASTS MADE FOR THE PRECEDING FIVE YEARS TO THE ACTUAL AND WEATHER-NORMALIZED PEAK DAY DEMAND AND ANNUAL THROUGHPUT BY CUSTOMER CLASS

Iowa Administrative Code: 35.10 (1)"c"

Forecasted vs. Actual Peak Day Demand by Customer Class

Actual and weather-adjusted annual throughput and peak demand for the past 5-years compared to forecasted values for that year are shown in Table 3. Contracts with pipeline suppliers include specific volumes to be delivered on a firm basis with interruptible volumes provided as available. Since Black Hills-IA gas interruptible customers are normally converted to an alternate fuel or shut down in accordance with their contracts during extreme periods of peak demand, data pertaining to peak demand is limited to firm gas requirements and obligations.

Weather Normalization of Actuals - Annual Throughput: Trend analysis was used to construct models of monthly gas sales by customer class, and these were used both to forecast and weather normalize sales. The coefficient for heating degree days for each class was multiplied by the degree day departure from normal to compute the weather adjustment. The models are described in section F.

Forecasts of Annual Throughput and Peak Day Demand: The forecast of annual throughput is based upon 30-year (1981-2010) monthly normal heating degree day as compiled by National Oceanic and Atmospheric Administration (NOAA) for Dubuque, IA (DBQ). The forecast of peak day demand is based on the coldest heating degree day experienced in 20 years.

TABLE 3
(Part 1 of 6)

Forecasts vs. Actuals -- State of Iowa

Historical Annual Sales
Residential

Black Hills-IA Gas: Residential Sales, Actual vs. Forecast Sales (MMCF)

Year	Actual Sales	Weather Adjust	WN Actual Sales	2012	2011	2010	2009
2008	11,551						
2009	11,074	-546	10,528				9,814
2010	10,556	-474	10,082			10,082	9,685
2011	10,490	41	10,531		10,680	10,162	9,557
2012	8,732	-1,443	7,289		10,202	10,110	9,432
2013				10,191	10,229	10,059	9,308
2012	Forecast vs. WNAct.				40.0%	38.7%	29.4%

TABLE 3
(Part 2 of 6)

Forecasts vs. Actuals -- State of Iowa

Historical Annual Sales
Commercial

Black Hills-IA Gas: Commercial Sales, Actual vs. Forecast Sales (MMCF)

Year	Actual Sales	Weather Adjust	WN Actual Sales	2012	2011	2010	2009
2008	6,539						
2009	6,682	-1,208	5,474				5,689
2010	6,062	69	6,131			6,154	5,729
2011	6,125	92	6,217		6,240	6,240	5,809
2012	5,250	864	6,114		6,271	6,271	5,850
2013				5,946	6,303	6,303	5,891
2012	Forecast vs. WNAct.				2.6%	2.6%	-4.3%

TABLE 3
(Part 3 of 6)

Forecasts vs. Actuals -- State of Iowa

Historical Annual Sales
Industrial

Black Hills-IA Gas: Industrial Sales, Actual vs. Forecast Sales (MMCF)

Year	Actual Sales	Weather Adjust	WN Actual Sales	2012	2011	2010	2009
2008	282						
2009	326	-	326				342
2010	354	-	354			300	342
2011	410	-	410		374	374	342
2012	493	-	493		374	374	342
2013				1,881	374	374	342
2012	Forecast vs. WNAct.				-24.1%	-24.1%	-30.6%

TABLE 3
(Part 4 of 6)

Forecasts vs. Actuals -- State of Iowa

Historical Annual Sales
Transportation

Black Hills-IA Gas: Transportation Sales, Actual vs. Forecast Sales (MMCF)

Year	Actual Sales	Weather Adjust	WN Actual Sales	2012	2011	2010	2009
2008	12,707						
2009	14,916		14,916				17,213
2010	17,423		17,423			16,600	17,213
2011	18,359	-	18,359		17,101	17,101	17,213
2012	18,294	-	18,294		17,101	17,101	17,213
2013				19,041	17,101	17,101	17,213
2012	Forecast vs. WNAct.				-6.5%	-6.5%	-5.9%

TABLE 3
(Part 5 of 6)

Forecasts vs. Actuals -- State of Iowa

Historical Annual Sales
Total Throughput

Black Hills-IA Gas: Total Throughput (Sales + Transport), Actual vs. Forecast Sales (MM

Year	Actual Sales	Weather Adjust	WN Actual Sales	2012	2011	2010	2009
2008	31,080						
2009	32,997	-1,753	31,244				33,172
2010	34,395	-405	33,990			33,136	33,083
2011	35,384	133	35,517		33,947	33,877	32,996
2012	32,769	-579	32,190		34,394	33,856	32,911
2013				37,111	34,006	33,837	32,828
2012	Forecast vs. WNAct.				6.8%	5.2%	2.2%

TABLE 3
(Part 6 of 6)

Forecasts vs. Actuals -- State of Iowa

Historical Annual Sales
Highest Day of System Deliveries (NNG, NGPL)

Black Hills-IA Gas: Peak Day, Actual vs. Forecast Sales (MCF)

Year	Actual Sales	Weather Adjust	WN Actual Sales	2012	2011	2010	2009
2008	215,687						
2009	233,262						274,048
2010	220,688					252,534	
2011	211,801				258,255		
2012	202,343			263,064			
2013							
2012	Forecast vs. WNAct.				21.9%	14.4%	17.5%

Forecasting Methodology, Data and Assumptions

Peak Day Forecast Methodology: The forecast for peak day demand was based on an analysis of the following historical data: 1) the actual peak day total throughput demand for Black Hills-IA natural gas customers, 2) the actual heating degree days on dates on which peak days occurred on NNG and NGPL pipelines.

The actual peak day demand for general service customers is determined as follows: Each town border station (TBS) records the gas delivered from the pipeline into the distribution system for each twenty-four-hour period. Black Hills-IA determines the coldest day of the year (usually experienced during January or February) and estimates the total sendout on the peak day. The large volume (firm and interruptible) and small volume interruptible town plant usage is netted with the estimated sendout; and the result is the natural gas delivered to general service customers. On the basis of the historical peak days, a forecast can be constructed to estimate peak day demand for Black Hills-IA gas utility customers. The forecast of peak day demand is based on an analysis of peak day throughput to Black Hills-IA. Data on peak day throughput, and HDD on days on which these peaks occurred, were used to forecast peak day demand.

Assumptions for Peak Day Forecasts: The overall assumptions underlying Black Hills-IA natural gas peak day forecasts are based historical peak day relationship to throughput on an actual and weather-normalized basis, which are applied to future throughput forecasts.

Annual Sales Forecast Methodology: The five-year forecast of total demand presented in this report follows similar methodology employed in previous Energy Efficiency Plan forecast filings.

Monthly data were used in the class end-use models to better capture the weather impact on monthly sales. Also, economic and natural gas price variables were used along with heating index (end-use efficiencies and market shares), and historical trend variables.

Separate forecasts were derived for each of major customer classes served by Black Hills-IA, as follows:

-Residential
-Commercial
-Industrial
-Other
-Transportation

The forecasting technique used for each customer class is historical trend analysis. In each model, the most current company data over the period January 2008 to December 2011, was used for residential, commercial and industrial classes to support the analysis.

Actual data per books on a monthly basis was used in the trend models. A weather variable, as measured by calendar month heating degree days (HDD), was explicitly entered into the model equations to capture the effect of weather variation on seasonal gas usage.

Data

The data used to develop the Black Hills-IA natural gas sales forecasts included company operating data for customers, sales volumes, and gas prices.

Company operating data was provided covering the period January 2008 through December 20011. This data consisted of monthly observations on sales, customers, and use per customer for each of the revenue classes.

Actual heating degree days and 10-year (Jul 2000-Jun 2010) normal heating degree days as compiled by the National Oceanic and Atmospheric Administration for four weather stations, weighted by usage were also used in weather normalizing sales.

Assumptions: Separate assumptions upon which the class sales forecasts are based are as follows:

1. In the short run, appliance stocks are fixed. Consumption arises from the varying utilization rates.
2. Appliance utilization rates are determined by the price of natural gas, real personal income, housing size, and heating degree days.
3. In the long run, the equipment stock is not fixed and energy-efficient equipment can be installed by households and firms.

After evaluating historical trends, a reasonable sales volume was determined and then left stable through the forecasted year of 2013. Documentation of data, forecast methodology, and assumptions used by Black Hills-IA to develop the class sales and peak day demand forecasts are presented in section F.

TABLE 4

Comparison of Peak Day Forecasts

Total NNG and NGPL

Black Hills-IA Gas: Comparison of Peak day Forecasts, Total NNG and NGPL (MCF)

1	2	3	4	5	6
Forecast MCF	Class(a)	2013 Forecast	2012 Forecast	Change	% Change
2013					
FIRM SALE &	Residential	110,367	108,669	1,698	1.6%
INTERRUPTIBLE SALES:	Commercial	64,473	62,132	2,341	3.8%
	Industrial	19,694	15,850	3,844	24.2%
Other Sales:	Other	392	302	90	29.9%
TRANSPORTATION:		68,350	71,301	-2,951	-4.1%
TOTAL		263,276	258,254	5,022	1.9%
2014					
FIRM SALE &	Residential	109,322	107,640	1,682	1.6%
INTERRUPTIBLE SALES:	Commercial	63,863	61,544	2,319	3.8%
	Industrial	19,507	15,700	3,807	24.2%
Other Sales:	Other	389	299	89	29.9%
TRANSPORTATION:		67,703	70,626	-2,923	-4.1%
TOTAL		260,784	255,809	4,975	1.9%
2015					
FIRM SALE &	Residential	109,171	107,491	1,680	1.6%
INTERRUPTIBLE SALES:	Commercial	63,774	61,458	2,316	3.8%
	Industrial	19,480	15,678	3,802	24.2%
Other Sales:	Other	388	299	89	29.9%
TRANSPORTATION:		67,609	70,528	-2,919	-4.1%
TOTAL		260,422	255,454	4,968	1.9%
2016					
FIRM SALE &	Residential	109,020	107,342	1,678	1.6%
INTERRUPTIBLE SALES:	Commercial	63,686	61,373	2,312	3.8%
	Industrial	19,453	15,657	3,797	24.2%
Other Sales:	Other	388	298	89	29.9%
TRANSPORTATION:		67,516	70,431	-2,915	-4.1%
TOTAL		260,062	255,101	4,961	1.9%
2017					
FIRM SALE &	Residential	108,869	107,194	1,675	1.6%
INTERRUPTIBLE SALES:	Commercial	63,598	61,289	2,309	3.8%
	Industrial	19,427	15,635	3,791	24.2%
Other Sales:	Other	387	298	89	29.9%
TRANSPORTATION:		67,423	70,333	-2,911	-4.1%
TOTAL		259,704	254,750	4,954	1.9%

(a) Peak day Demand is based on coldest weather experienced in 20 yrs for Dubuque, Des Moines, Spencer, and Council Bluffs. Class peak day demand estimated proportional to system peak day.

Explanation of Differences Between Current and Previous Total Forecasts:

Table 5 contains a presentation of the current 2013 forecast of total sales and transportation compared with the prior 2012 forecast of total sales and transportation.

The revisions between the 2012 and 2013 forecasts increase total sales and transportation, primarily due to an increase in the industrial and transportation volume forecast, while residential and commercial forecasts increased slightly.

TABLE 5

Comparison of Annual Sales Forecasts

Total NNG and NGPL

Black Hills-IA Gas: Comparison of Annual Sales and Throughput Forecasts (MCF)

1	2	3	4	5	6
Forecast MCF	Class(a)	2013 Forecast	2012 Forecast	Change	% Change
2013					
FIRM SALE &	Residential	10,191,378	10,257,250	-65,872	-0.6%
INTERRUPTIBLE SALES:	Commercial	5,945,681	6,240,000	-294,319	-4.7%
	Industrial	1,880,875	373,671	1,507,204	403.4%
Other Sales:	Other	52,071	0	52,071	-
TRANSPORTATION:		19,041,288	18,358,692	682,596	3.7%
TOTAL		37,111,293	35,229,613	1,881,680	5.3%
2014					
FIRM SALE &	Residential	10,140,094	10,155,802	-15,708	-0.2%
INTERRUPTIBLE SALES:	Commercial	5,945,681	6,240,000	-294,319	-4.7%
	Industrial	1,580,875	409,723	1,171,152	285.8%
Other Sales:	Other	52,071	0	52,071	-
TRANSPORTATION:		19,041,288	18,358,692	682,596	3.7%
TOTAL		36,760,009	35,164,217	1,595,792	4.5%
2015					
FIRM SALE &	Residential	10,089,070	10,107,300	-18,230	-0.2%
INTERRUPTIBLE SALES:	Commercial	5,945,681	6,240,000	-294,319	-4.7%
	Industrial	1,580,875	409,723	1,171,152	285.8%
Other Sales:	Other	52,071	0	52,071	-
TRANSPORTATION:		19,041,288	18,358,692	682,596	3.7%
TOTAL		36,708,984	35,115,715	1,593,269	4.5%
2016					
FIRM SALE &	Residential	10,038,303	10,058,750	-20,447	-0.2%
INTERRUPTIBLE SALES:	Commercial	5,945,681	6,240,000	-294,319	-4.7%
	Industrial	1,580,875	409,723	1,171,152	285.8%
Other Sales:	Other	52,071	0	52,071	-
TRANSPORTATION:		19,041,288	18,358,692	682,596	3.7%
TOTAL		36,658,217	35,067,165	1,591,052	4.5%
2017					
FIRM SALE &	Residential	9,987,792	10,010,433	-22,641	-0.2%
INTERRUPTIBLE SALES:	Commercial	5,945,681	6,240,000	-294,319	-4.7%
	Industrial	1,580,875	409,723	1,171,152	285.8%
Other Sales:	Other	52,071	0	52,071	-
TRANSPORTATION:		19,041,288	18,358,692	682,596	3.7%
TOTAL		36,607,707	35,018,848	1,588,859	4.5%

FORECAST OF DEMAND FOR TRANSPORTATION
VOLUME FOR BOTH PEAK DAY DEMAND AND ANNUAL THROUGHPUT
FOR EACH OF THE NEXT FIVE YEARS

Iowa Administrative Code: 35.10(1)"d"

This information is included in the section a.

EXISTING CONTRACT DELIVERABILITY BY SUPPLIER, CONTRACT AND RATE SCHEDULE FOR THE LENGTH OF EACH CONTRACT

Iowa Administrative Code: 35.10(1)"e"

See the following Table 6.

TABLE 6

Levels Allocated to State of Iowa

Firm Entitlement 2008-2012

(NNG and NGPL Pipelines)

Black Hills-IA Natural Gas Utility, Firm Entitlement Contracts, 2008-2012

NNG Entitlement						
(MMBTU)	TF12B	TF12V	TFF	TF5	TFX	Total
2008						
Jan to Mar:	27,536	21,760		19,013	127,613	195,922
Apr:	27,536	21,760			37,675	86,971
May to Sep:	27,536	21,760			9,560	58,856
Oct:	27,536	21,760			37,675	86,971
Nov to Dec:	27,536	21,760		19,013	127,613	195,922
2009						
Jan to Mar	36,756	15,657		19,720	137,266	209,399
Apr	36,756	15,657			39,301	91,714
May to Sep	36,756	15,657			9,973	62,386
Oct	36,756	15,657			39,301	91,714
Nov to Dec	36,756	15,657		19,720	137,266	209,399
2010						
Jan to Mar	32,917	15,577		18,393	128,109	194,996
Apr	32,917	15,577			36,090	84,584
May to Sep	32,917	15,577			9,654	58,148
Oct	32,917	15,577			36,156	84,650
Nov to Dec	32,917	15,577		18,393	128,109	194,996
2011						
Jan to Mar	29,180	17,429		17,792	124,173	188,574
Apr	29,180	17,429			36,117	82,726
May to Sep	29,180	17,429			9,555	56,164
Oct	29,180	17,429			36,181	82,790
Nov to Dec	29,180	17,429		17,792	124,173	188,574
2012						
Jan to Mar	37,489	10,411		18,097	127,518	193,515
Apr	37,489	10,411			36,667	84,567
May to Sep	37,489	10,411			10,553	58,453
Oct	37,489	10,411			36,732	84,632
Nov to Dec	37,489	10,411		18,097	127,518	193,515
NGPL Entitlement						
	FTSG					
2008						
Jan to Dec:	2,900					
2009						
Jan to Dec:	2,900					
2010						
Jan to Dec:	2,900					
2011						
Jan to Dec:	2,900					
2012						
Jan to Dec:	2,900					

EXPLANATION OF ALL SIGNIFICANT METHODS AND DATA USED, AS WELL AS ASSUMPTIONS MADE, IN THE CURRENT <u>FIVE-YEAR FORECASTS</u>

Iowa Administrative Code: 35.10(1)"f"

Data and Principal Assumptions
Used in Forecasting

This appendix presents documentation of data, forecast methodology and assumptions used to develop the total demand forecast for Black Hills Energy.

FORECAST METHODOLOGY

Annual Throughput Forecast

Monthly data from 2008 through 2011 were used to build historical trend models.

Firm monthly sales projections were done on a usage-per-customer basis (UPC) for the residential class. Therefore, a residential UPC and a customer forecast were required for these projections. Commercial and Industrial sales were projected directly from monthly class sales. Weather, represented by Heating Degree Days (HDD) variables was used in the historical trend models.

Peak Day Demand Forecast

Heating Degree Days (HDD) on a 65F and 55F basis were used as the weather variables, to explain daily throughput, including linear time trend, calendar variables for holiday, days of the week and monthly intercepts by pipeline zone. See screenshots on the following pages from daily peak model for model statistics.

Residential Sales Model

Zone A1 Firm Peak Model, 2012-2013 Heating Season (Nov-Mar)

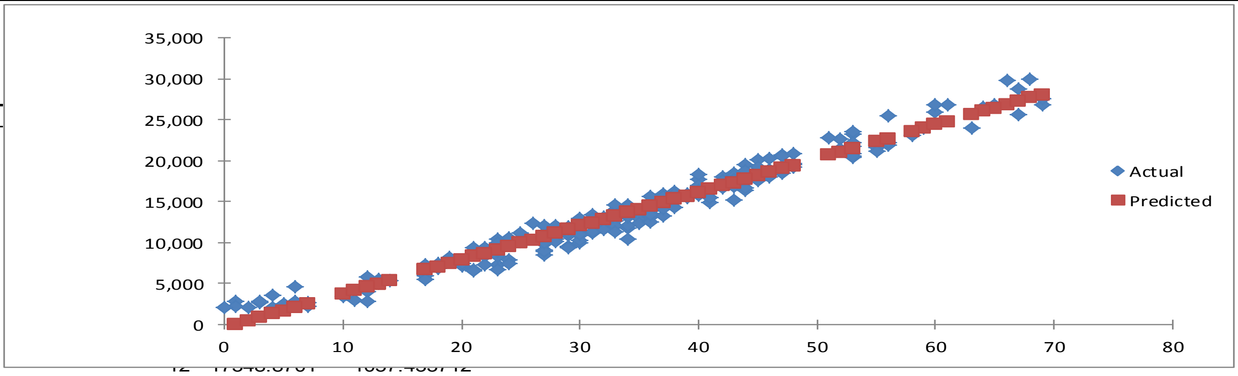
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.982
R Square	0.963
Adjusted R Square	0.963
Standard Error	1205
Observations	218

ANOVA

	df	*SS*	*MS*	*F*	*Sig F*
Regression	1	8256514315	8256514315	5685	4.0232E-157
Residual	216	313713020	1452375		
Total	217	8570227336			

	Coefficients	*SE*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95%*	*Upper 95%*
Intercept	-373.63	203.72	-1.83	0.068	-775.17	27.91	-775.17	27.91
X Variable 1	412.15	5.47	75.40	0.000	401.38	422.93	401.38	422.93



Iowa Zone B Firm Peak Model, 2012-2013 Heating Season (Nov-Mar)

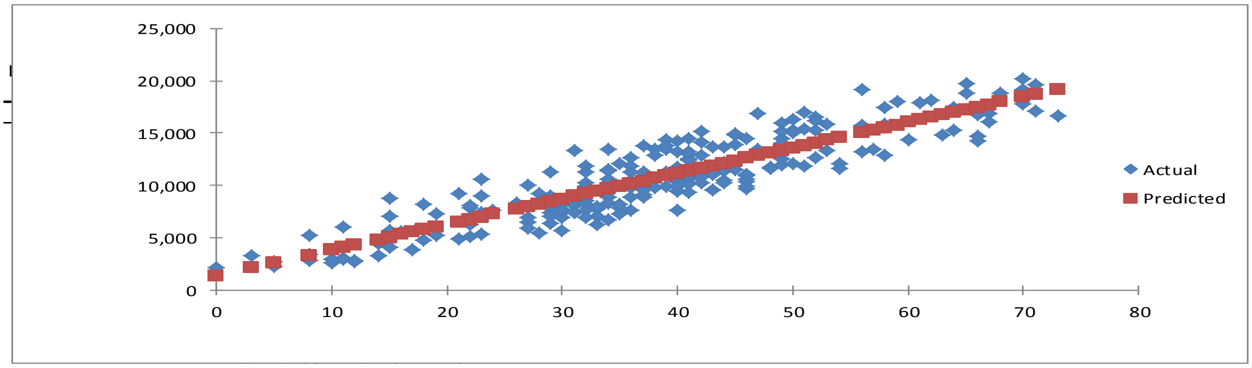
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.901
R Square	0.812
Adjusted R Square	0.811
Standard Error	1799
Observations	218

ANOVA

	df	*SS*	*MS*	*F*	*Sig F*
Regression	1	3012465276	3012465276	931	3.00281E-80
Residual	216	699107043	3236607		
Total	217	3711572319			

	Coefficients	*SE*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95%*	*Upper 95%*
Intercept	1388.58	324.64	4.28	0.000	748.70	2028.45	748.70	2028.45
X Variable 1	243.73	7.99	30.51	0.000	227.99	259.48	227.99	259.48



Residential Sales Model

Iowa Zone C Firm Peak Model, 2012-2013 Heating Season (Nov-Mar)

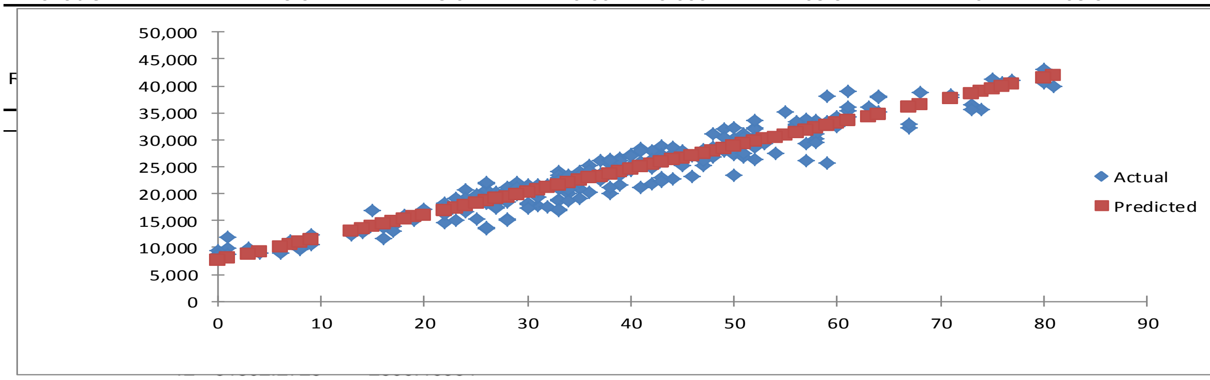
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.958
R Square	0.919
Adjusted R Square	0.918
Standard Error	2221
Observations	218

ANOVA

	df	*SS*	*MS*	*F*	*Sig F*
Regression	1	12035338240	12035338240	2439	1.1713E-119
Residual	216	1065716188	4933871		
Total	217	13101054428			

	Coefficients	*SE*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95%*	*Upper 95%*
Intercept	7559.48	363.21	20.81	0.000	6843.59	8275.37	6843.59	8275.37
X Variable 1	425.31	8.61	49.39	0.000	408.34	442.29	408.34	442.29



Iowa Zone D Firm Peak Model, 2012-2013 Heating Season (Nov-Mar)

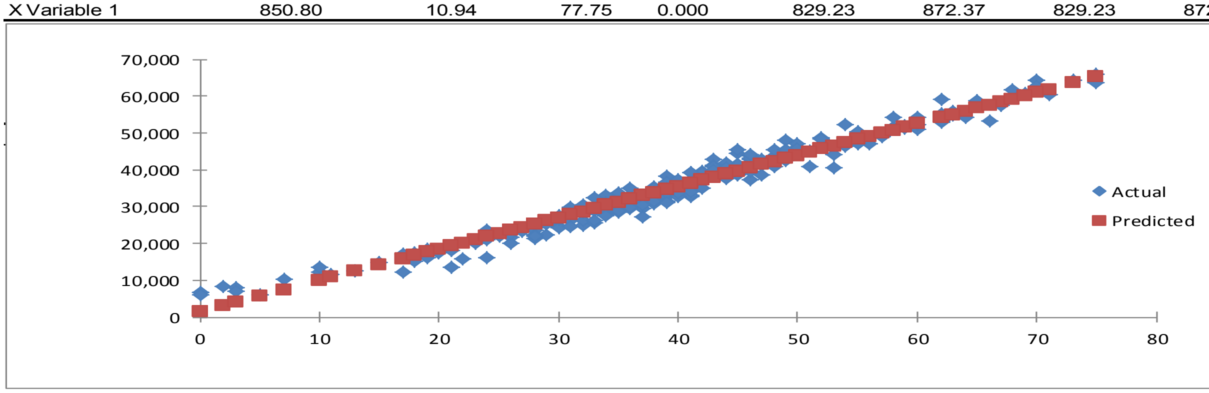
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.983
R Square	0.965
Adjusted R Square	0.965
Standard Error	2426
Observations	218

ANOVA

	df	*SS*	*MS*	*F*	*Sig F*
Regression	1	35570663359	35570663359	6045	6.7057E-160
Residual	216	1271044934	5884467		
Total	217	36841708292			

	Coefficients	*SE*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95%*	*Upper 95%*
Intercept	1433.93	457.82	3.13	0.002	531.56	2336.30	531.56	2336.30
X Variable 1	850.80	10.94	77.75	0.000	829.23	872.37	829.23	872.37



Residential Sales Model

Iowa NGPL Firm Peak Model, 2012-2013 Heating Season (Nov-Mar)

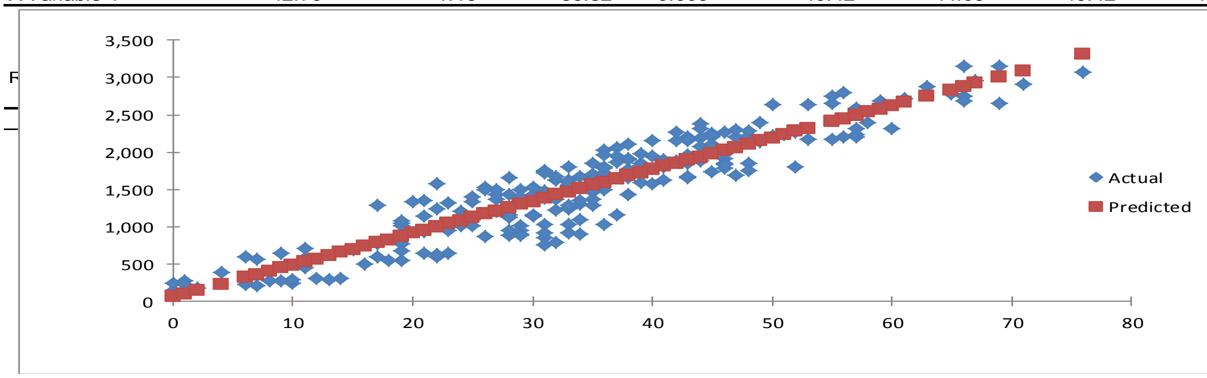
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.929
R Square	0.863
Adjusted R Square	0.862
Standard Error	259
Observations	218

ANOVA

	df	SS	MS	F	Sig F
Regression	1	90606529.38	90606529.38	1356	4.76094E-95
Residual	216	14435598	66831		
Total	217	105042127.1			

	Coefficients	SE	t Stat	P-value	Lower 95%	Upper 95%	Lower 95%	Upper 95%
Intercept	59.82	43.97	1.36	0.175	-26.85	146.48	-26.85	146.48
X Variable 1	42.70	1.16	36.82	0.000	40.42	44.99	40.42	44.99



MARGINS OF ERROR FOR EACH

ASSUMPTION OR FORECAST

Iowa Administrative Code: 35.10(1)"g"

Items That Could Significantly Alter the Demand, Supply, or Projections of Cost

Econometric/end-use models were used to forecast monthly and peak day demand. These models were developed to quantify the impact on gas demand of the significant factors that determine residential, commercial and industrial sales volumes and peak day demand. In summary, the primary determinants and relationships which have been quantified for the Black Hills-IA service area are:

- Customer Growth
- Personal Income Growth
- Price of natural gas and elasticity
- Price of alternate fuels
- Real GSP for gas utility service area

The Black Hills-IA gas demand forecasts are conditional upon the forecasts of the above listed quantified determinants. An error in forecast will occur if the basic input assumptions vary from actual results.

The sensitivity analysis (presented in the next section) quantifies margins of error for two major peak day demand assumptions: 1) growth in the number of households and 2) growth in commercial, industrial and transportation sales volume forecasts. The sensitivity analysis presents the impact on peak day demand variations in the number of residential households in the Aquila-IA gas service area and high and low gas price projections. These variations address the impact of error exceeding reasonable margins.

SENSITIVITY ANALYSIS

Iowa Administrative Code: 35.10(1)"h"

Sensitivity Analysis

When making an analysis of the validity of Black Hills-IA forecasting, at this time only the peak day demand is relevant. All of Black HIlls-IA gas supplies are purchased on the basis of daily entitlement and "demand for gas" is by definition daily demand. Therefore, this sensitivity analysis will relate to the five-year annual throughput and peak day forecasts. The basic assumptions used in the analysis and resulting scenarios are as follows:

Assumptions: The demand for natural gas, the supply of gas, and purchase cost projections are influenced by a host of uncontrollable variables (external to Black Hills-IA) and a lesser number of controllable variables. Econometric/end-use class sales models were developed to take as many as possible of the important factors into consideration. These models rely on historical data which was used to determine the factors which have significant impact on the monthly sales and peak day demand for gas in the Black Hills-IA service area.

Internal factors such as company operating policies, procedures and marketing efforts have an effect on the demand for any saleable commodity, including natural gas. These factors include new customer connection policies, sales promotional campaigns, personal selling efforts, and so on. In an effort to cope with these factors, the peak day forecast was based on customer growth in all firm classes. Therefore, customer counts constitute a surrogate measure of internal company operations which influence peak day demand for gas.

The following assumptions used in Black Hills-IA class sales and peak day forecast could change the projected demand for gas:

1. Peak day firm demand is projected based on HDD on peak days.
2. The number of customers can be predicted reliably.
3. Conservation of energy usage, including natural gas, from historical energy-efficiency measures will persist for the duration of the forecast period.
4. Historical company connection policies, internal marketing and other operations which influence customer growth will continue.
5. Large volume contract customers will use their full firm requirements on the peak day.
6. Contract customers' firm entitlement will remain at present levels.
7. Weather cannot be predicted reliably; thus, any forecast of demand cannot account accurately for weather-related factors.

Effect of Excessive Errors.

The annual class sales and peak day forecasts are sensitive to variations in the residential customer forecasts and growth in commercial, industrial and transportation volumes. Two scenarios are presented in Tables 7 (Annual Throughput) and 8 (Peak Day Demand) to quantify high and low cases based on variations in these variables. A high case, where class customers and sales are projected to grow at higher rates than in the base case forecast; and a low case, where the customers and sales are project to grow at lower rates, or decline, compared to the base case forecast.

TABLE 7

Annual Throughput, High-Low Forecasts

Black Hills-IA Natural Gas Utility, High and Low 2013 Forecasts for Annual Throughput (MMCF)

Year	High Case(a)	Base Case	Low Case(b)	High-Base	Low-Base	H-B % Chg	L-B % Chg
2013	37,417,981	37,111,293	37,051,331	306,688	(59,961)	0.8%	-0.2%
2014	37,066,082	36,760,009	36,701,994	306,073	(58,015)	0.8%	-0.2%
2015	37,014,445	36,708,984	36,650,816	305,460	(58,168)	0.8%	-0.2%
2016	36,963,069	36,658,217	36,599,897	304,851	(58,321)	0.8%	-0.2%
2017	36,911,952	36,607,707	36,549,234	304,245	(58,472)	0.8%	-0.2%
G%/Yr	-0.1%	-0.1%	-0.1%				

(a) High case assumes 1.2%/year residential customer growth, 1.5%/year commercial sales growth, constant industrial sales, and .5%/year transportation sales growth.
(b) Low case assumes .3%/year residential customer growth, .3%/year commercial sales growth, industrial sales decline -.7%/year, and transportation sales decline .5%/year

TABLE 8

Annual Throughput, High-Low Forecasts

Black Hills-IA Gas: High and Low 2013 Forecasts for Peak Day Demand (MMCF)

Year	High Case(a)	Base Case	Low Case(b)	High-Base	Low-Base	H-B % Chg	L-B % Chg
2013	265,238	263,064	262,639	2,174	(425)	0.8%	-0.2%
2014	262,956	260,784	260,373	2,171	(412)	0.8%	-0.2%
2015	262,589	260,422	260,010	2,167	(413)	0.8%	-0.2%
2016	262,225	260,062	259,648	2,163	(414)	0.8%	-0.2%
2017	261,862	259,704	259,289	2,158	(415)	0.8%	-0.2%
G%/Yr	-0.1%	-0.1%	-0.1%				

(a) High Case peak day assumed to be proportional to Base Case
(b) Low Case peak day assumed to be proportional to Base Case based on throughput.

Appendix F. Rate Tariffs

Black Hills/Iowa Gas Utility Company, L.L.C.
d/b/a Black Hills Energy

Gas Tariff
Volume 1
Schedule of Rates
Applying to Black Hills Energy's
Town Plant and Mainline Customers
In the State of Iowa

Filed with the
Iowa Utilities Board

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SCHEDULE OF RATES

I. Rate Schedule — Sheet No.

N

Notwithstanding any other provision of this Iowa Utilities Board Gas Tariff, Sixth Revised Rate Schedule Volume No. 1 or any contracts with customers referred to specifically or generally in Sheet Nos. 3 through 67a, as revised, all rates and charges contained in this Tariff or the aforesaid contracts may be modified at any time by a subsequent filing made pursuant to the provisions of Chapter 476 of the Code of Iowa.

TABLE OF CONTENTS
GAS

Notwithstanding any other provision of this Iowa Utilities Board Gas Tariff, Fifth Revised Rate Schedule Volume No. 1 or any contracts with customers referred to specifically or generally in Sheet Nos. 3 through 67a, as revised, all rates and charges contained in this Tariff or the aforesaid contracts may be modified at any time by a subsequent filing made pursuant to the provisions of Chapter 476 of the Code of Iowa.

RATE SCHEDULE GS-1, GENERAL SERVICE GAS

Availability	Service under this rate schedule is available to any customer located in the towns as listed on Sheet No. 44.
Applicability and Character of Service	This rate schedule shall apply to firm gas service for customers whose normal requirement does not exceed 199 Dekatherms on a peak day, and such service normally shall not be subject to curtailment or interruption, but will be subject to curtailment by pipeline supplier in compliance with their approved Federal Energy Regulatory Commission curtailment plan.
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthly Charge: A. Residential $18.25 per meter B. Commercial & Industrial $29.00 per meter 2. Non-Gas Cost: $0.11635 per Therm I 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes. T
Minimum Bill	Residential - $18.25 Commercial and Industrial - $29.00
Taxes	The total bill is subject to state and local taxes.
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.

RATE SCHEDULE GS-2 GENERAL SERVICE – AIR CONDITIONING
GAS

1. Availability: Service under this rate schedule is available to any customer located in the towns as listed on Sheet No. 44.

2. Applicability and Character of Service: This rate schedule shall apply to separately metered gas service used exclusively in a gas cooling application. Customers eligible to be served on the air conditioning rate are those whose non-gas cooling usage is provided through a general service rate.

3. Rate:

   A. Rate per month:

   T

   Basic monthly charge - Residential - $9.20 per meter T
   - Commercial and Industrial - $11.20 per meter

   Non-Gas Cost - $0.118680

   B. After 20 days there shall be a 1-1/2% charge on the unpaid balance.

   C. Above rates are subject to the Large Volume Interruptible Purchased Gas Adjustments Uniform Clause Information Sheet No. 48.

   D. Above rates are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.

4. The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28.

5. The total bill is subject to state and local taxes.

6. Minimum Bill: Residential - $9.20
   Commercial and Industrial - $11.20

7. General Terms and Conditions: The General Terms and Conditions contained in this tariff shall apply to this rate schedule.

RATE SCHEDULE
GAS

HELD FOR FUTURE USE

RATE SCHEDULE 491, LARGE VOLUME FIRM SERVICE GAS

Availability	Service under this rate schedule is available to the following customers located near the indicated town: Massena, Iowa: Natural Gas Pipeline Company of America.	
Applicability and Character of Service	This rate schedule shall apply to firm gas service for use in customers' pumping station served off the pipeline of the supplier. The Massena station is not to exceed 700 Dekatherms per day. Peak day gas requirements of 200 Dekatherms or more will be considered "Large Volume."	
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthly Charge: $200.00 per meter 2. Non-Gas Cost: $0.02364 per Therm 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	I
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the basic monthly charge.	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE LVJ-1, LARGE VOLUME JOINT GAS SERVICE GAS

Availability	All areas in Northern Natural Gas Company's Rate Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to joint gas service consisting of a base of firm gas volumes, supplemented by interruptible gas volumes. Company will calculate a peak day requirement for each premise by dividing the peak month usage in the last thirty six (36) months by 20. Peak day gas requirements of 200 Dekatherms or more will be considered “Large Volume.”	
Rate	The customer’s monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $200.00 per meter. 2. Demand Charge - Customer’s MDQ times the Demand Charge Rate - $0.05010 per Therm 3. Non-Gas Cost: $0.02364 per Therm 4. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 5. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	I
Basic Monthly Charge	The “customer charge” is a measure of the costs associated with the Company’s facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the contract demand charge plus the basic monthly charge	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28.	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company’s PGA mechanism.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE 518, MAINLINE LARGE VOLUME JOINT GAS SERVICE GAS

1. Availability: All areas in Northern Natural Gas Company's Rate Zone 1.

2. Applicability and Character of Service: This rate schedule shall apply to industrial customers serviced off the pipeline of the supplier taking joint gas service consisting of a base of firm gas volumes, supplemented by interruptible gas volumes. Company will calculate a peak day requirement for each premise by dividing the peak month usage in the last thirty six (36) months by 20. Peak day gas requirements of 200 Dekatherms or more will be considered "Large Volume." T T T

3. Rate: T

   A. Contract Demand:
      Non-Gas Cost - $0.0501 per Therm T
      Sales Volumes:
      Non-Gas Cost - $0.00500 per Therm
   B. After 20 days there shall be a 1-1/2% charge on the past due amount.
   C. There shall be a basic monthly charge of $150.00 per meter.
   D. The minimum bill shall be the contract demand charge plus the basic monthly charge.
   E. Above rates are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48.
   F. Any Customer who has executed a LVCS contract with Company will be subject to Rider No. 1D, Large Volume Contract Service Rider. T
   G. Above rates are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.

4. The total bill is subject to state and local taxes.

5. Penalty for Unauthorized Takes When Service is Interrupted: Applicable rate in Paragraph 3A above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.

6. General Terms and Conditions: The General Terms and Conditions contained in this tariff shall apply to this rate schedule.

7. Billing Interval: Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).

RATE SCHEDULE SVI-1, SMALL VOLUME INTERRUPTIBLE GAS

Availability	Service under this rate schedule is available to any customer located in the towns as listed on Sheet No. 44
Applicability and Character of Service	This rate schedule shall apply to small volume gas service, which is subject to interruption at any time upon order of Company. Peak day gas requirements which exceed 24 Dekatherms per day but are less than 200 Dekatherms per day will be considered "Small Volume."
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $75.00 per meter. 2. Non-Gas Cost: $0.05237 per Therm I 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes. T
Minimum Bill	The minimum bill shall be the basic monthly charge.
Taxes	The total bill is subject to state and local taxes.
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28.
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.

RATES
GAS

HELD FOR FUTURE USE

RATES
GAS

HELD FOR FUTURE USE

RATE SCHEDULE LVI-2, LARGE VOLUME INTERRUPTIBLE – ELECTRIC GENERATION GAS

Availability	All areas in Northern Natural Gas Company's Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to electrical generation customers. This service is subject to interruption at any time upon order of Company. Peak day gas requirements of 200 Dekatherms or more will be considered "Large Volume."	
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $200.00 per meter. 2. Non-Gas Cost: $0.02364 per Therm 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	I
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the basic monthly charge.	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28.	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.	
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE LVI-3, LARGE INTERRUPTIBLE – GRAIN DRYER GAS

Availability	All areas in Northern Natural Gas Company's Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to large volume gas service for commercial or industrial, having predominately seasonal needs, such as grain drying, the heating of anhydrous ammonia or other such uses. This service is subject to interruption at any time upon order of Company. Peak day gas requirements of 200 Dekatherms or more will be considered "Large Volume."	
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $600.00 per meter per month for the 4 months, September through December. 2. Non-Gas Cost: $0.02364 per Therm 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	I
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the basic monthly charge.	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.	
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

GAS

HELD FOR FUTURE USE

RATE SCHEDULE LVI-1, LARGE VOLUME INTERRUPTIBLE SERVICE GAS

Availability	All areas in Northern Natural Gas Company's Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to large volume gas service, which is subject to interruption at any time upon order of Company. Peak day gas requirements of 200 Dekatherms or more will be considered "Large Volume."	
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $200.00 per meter 2. Non-Gas Cost: $0.02364 per Therm 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	I
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the basic monthly charge.	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.	
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE 299 MAINLINE LV INTERRUPTIBLE SERVICE GAS

Availability	All areas in Northern Natural Gas Company's Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to large volume gas service, which is subject to interruption at any time upon order of Company. Peak day gas requirements of 200 Dekatherms or more will be considered “Large Volume.”	
Rate	The customer’s monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $200.00 per meter 2. Non-Gas Cost: $0.0050 per Therm 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	I
Basic Monthly Charge	The “customer charge” is a measure of the costs associated with the Company’s facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the basic monthly charge.	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company’s PGA mechanism.	
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE SVJ-1, SMALL VOLUME JOINT SERVICE GAS

Availability	All areas in Northern Natural Gas Company's Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to joint gas service consisting of a base of firm gas volumes, supplemented by interruptible gas volumes. Company will calculate a peak day requirement for each premise by dividing the peak month usage in the last thirty six (36) months by 20. Peak day gas requirements that exceed 24 Dekatherms per day but are less than 200 Dekatherms per day, will be considered "Small Volume."	
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $75.00 per meter 2. Contract Demand - $0.05010 per Therm 3. Non-Gas Cost: $0.05237 per Therm 4. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 5. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	 I
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the contract demand charge plus the basic monthly charge	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.	
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE 221, MAINLINE SMALL VOLUME GAS SERVICE GAS

Availability	All areas in Northern Natural Gas Company's Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to industrial customers served off the pipeline of the supplier taking joint gas service consisting of a base of firm gas volumes, supplemented by interruptible gas volumes. Company will calculate a peak day requirement for each premise by dividing the peak month usage in the last thirty six (36) months by 20. Peak day gas requirements, which exceed 24 Dekatherms per day but are less than 200 Dekatherms per day, will be considered "Small Volume."	
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - \$75.00 per meter 2. Contract Demand - \$0.05010 per Therm 3. Non-Gas Cost: \$0.00500 per Therm 4. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 5. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the contract demand charge plus the basic monthly charge	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or \$20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.	
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE 429, MAINLINE SMALL VOLUME INTERRUPTIBLE GAS

Availability	All areas in Northern Natural Gas Company's Zone 1.	
Applicability and Character of Service	This rate schedule shall apply to industrial customers served off the pipeline of the supplier taking small volume gas service which is subject to interruption at any time upon order of Company. Peak day gas requirements, which exceed 24 Dekatherms per day but are less than 200 Dekatherms per day will be considered "Small Volume."	
Rate	The customer's monthly bill shall be the sum of the following components: 1. Basic Monthy Charge - $75.00 per meter 2. Non-Gas Cost: $0.00500 per Therm 3. Purchase Gas Cost: The rates above are subject to Purchased Gas Adjustments Uniform Clause Information Sheet No. 48. 4. Energy Efficiency Cost Recovery: The rates above are subject to Energy Efficiency Cost Recovery Information Sheet No. 52.	
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumes.	T
Minimum Bill	The minimum bill shall be the basic monthly charge.	
Taxes	The total bill is subject to state and local taxes.	
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	
Pressure Adjustment	The measured volume is subject to a pressure factor adjustment as listed on Sheet No. 28	
Penalty for Unauthorized Takes When Service is Interrupted:	Applicable rate above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.	
Affidavit Required	Customers electing interruptible service must sign an affidavit confirming the customer has an alternative fuel capability or is willing to discontinue gas service during periods of curtailment.	
Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	
Billing Interval	Customers served under this tariff sheet may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	

RATE SCHEDULE SLV – SUPER LARGE VOLUME GAS

Availability	Service under this rate schedule is available to large volume customers supplied through Northern Natural Gas Company.	N
Applicability and Character of Service	This rate schedule shall apply to joint gas service consisting of a base of firm gas volume, supplemented by additional interruptible gas volumes authorized from day to day. Customer must have and maintain both the proven capability and adequate fuel supplies to use alternative fuel if the Company's service to such customer is interrupted. At Company's request, the customer must demonstrate it has such capability and fuel supplies for amounts in excess of firm entitlement volumes to maintain operations during periods of curtailment. Customer must have capacity to take 4,000 Mcf or more per day and annual consumption of 1 Bcf (1 million Mcf), except that, where consumption falls below this level due exclusively to efforts to conserve energy, or temporarily due to a strike or shutdown, customer is still eligible to take service under this tariff. Customer must document conservation efforts to justify consumption below 1 Bcf.	N
Cost/Benefit Analysis	In determining the rate, Company shall evaluate the individual customer's situation and perform a cost/benefit analysis.	N
Rate	The rate shall be negotiated between the parties and must pass the cost/benefit analysis.	N
Contracts	Service contracts with customers on this rate will be filed with the Board.	N
Basic Monthly Charge	The "customer charge" is a measure of the costs associated with the Company's facilities that are not jointly used by other customers and other costs related directly to service to the individual customer. These costs are fixed and do not vary with the amount of gas the customer consumed.	T
Minimum Bill	The monthly minimum bill shall be the customer charge, the daily firm capacity charge, the demand charge and the applicable commodity charge for all volumes taken.	N
Penalty for Unauthorized Takes When Service is Interrupted	Applicable rate in Paragraph 3A above per Dekatherm plus the greater of either the pipeline daily delivery variance charges or $20.00 per Dekatherm for gas used in excess of the volumes of gas to which customer is limited. Revenues for unauthorized takes will be credited to the Company's PGA mechanism.	N
Taxes	The total bill is subject to state and local taxes.	N

RATE SCHEDULE SLV – SUPER LARGE VOLUME (continued)
GAS

Billing Interval	Customers served under this tariff may be billed on more frequent than monthly intervals pursuant to Iowa Adm. Code 199-19.3(7).	N
Late Payment Charge	After 20 days there shall be a 1-1/2% charge on the unpaid balance.	N
Demand Charge	In order to meet customers' maximum demands, Company must design and have facilities sized to meet those maximum demands, regardless of whether the customer uses that volume of gas every day. Company incurs substantial costs associated with the investment and the operation and maintenance expenses associated with gas distribution facilities sized to accommodate individual customers' maximum rate of gas usage. Therefore, the level of "Peak Usage" or "Maximum Daily Quantity" (MDQ) represents the measure of Customer's use of capacity, and when applied to the Demand Charge, Customer's responsibility for Company's cost of maintaining that peak day capacity.	N
Maximum Daily Quantity (MDQ)	A Customer's MDQ represents the maximum quantity of gas that the customer requires and hence the capacity of the distribution facilities needed to serve that customer. The maximum quantity of gas a customer consumes is calculated using the definition for "Maximum Daily Quantity" as defined on Sheet GT-2. Company will estimate the number of units for new customers.	N
General Terms and Conditions	The General Terms and Conditions contained in this tariff shall apply to this rate schedule.	N

TAX ADJUSTMENT CLAUSE
GAS

When any franchise, occupation, sales, license, excise, privilege or similar tax or fee of any kind is imposed upon the Company by any governmental authority based upon (1) the sale of gas service to customers, (2) the amount of gas energy sold to customers, (3) the gross receipts, net receipts or revenues to the Company therefrom, such tax or fee or value of service shall, insofar as practical, be charged on a pro rata basis to all customers receiving gas service from the Company within the boundaries of such taxing authority. Any such charge shall continue in effect only for the duration of such tax, assessment or service period. N N N N N N

Current Applicable Requirements: N

1. Iowa Sales Tax. A state sales tax, as set forth in Section 422.43 of the Iowa Code, shall be applied to all billings for gas service, unless excepted under the provisions of Section 422.45 of the Iowa Code and the regulation applicable thereto. N N N

2. Local Option Sales Tax. Where a local option tax, as set forth in Section 422B of the Iowa Code, has been imposed in a county, it shall be applied to all billings for gas service to customers within the designated area(s) of application, except where such billings are subject to a franchise or user fee and therefore exempt under Rule 701-701.9 of the Iowa Administrative Code. N N N N

3. School Infrastructure Local Option Tax. Where a school infrastructure local option tax, as set forth in Section 422E of the Iowa Code, has been imposed in a county, it shall be applied to all billings for gas service to customers within the county, except where such billings are subject to a franchise or user fee and therefore exempt inder Rule 701-107.9 of the Iowa Adminstrative Code. N N N N

4. Franchise Requirements. A franchise fee shall be billed to all billings for gas service furnished within the cities identified in the table below, showing the city franchise fee or rate, and the effective date of the charge. However, the franchise fee shall not be assessed to the city as a customer. The franchise fee will also be charged on the sale of natural gas sold to transportation customers by third-party suppliers where the franchise provides that such sales are subject to the franchise fee. N N N N N

TAX ADJUSTMENT CLAUSE
GAS

Description	Percent	Description	Percent
County Taxes		County Taxes (continued):	
ADAIR COUNTY IA	1.0	HAMILTON COUNTY IA	2.0
ALLAMAKEE COUNTY IA	2.0	HANCOCK COUNTY IA	2.0
AUDUBON COUNTY IA	2.0	JACKSON COUNTY IA	2.0
BENTON COUNTY IA	1.0	JASPER COUNTY IA	1.0
BLACK HAWK COUNTY IA	2.0	JONES COUNTY IA	2.0
BOONE COUNTY IA	2.0	KOSSUTH COUNTY IA	2.0
BREMER COUNTY IA	2.0	LINN COUNTY IA	1.0
BUCHANAN COUNTY IA	2.0	MILLS COUNTY IA	2.0
BUTLER COUNTY IA	2.0	MITCHELL COUNTY IA	2.0
CALHOUN COUNTY IA	1.0	MONONA COUNTY IA	2.0
CARROLL COUNTY IA	1.0	O'BRIEN COUNTY IA	2.0
CASS COUNTY IA	1.0	POCAHONTAS COUNTY IA	2.0
CLAY COUNTY IA	2.0	POLK COUNTY IA	1.0
CLAYTON COUNTY IA	2.0	POTTAWATTAMIE COUNTY	2.0
CRAWFORD COUNTY IA	2.0	SAC COUNTY IA	1.0
DALLAS COUNTY IA	1.0	STORY COUNTY IA	2.0
EMMET COUNTY IA	1.0	WEBSTER COUNTY IA	1.0
FAYETTE COUNTY IA	2.0	WINNEBAGO COUNTY IA	2.0
FREMONT COUNTY IA	2.0	WINNESHIEK COUNTY IA	2.0
HANCOCK CO IA (Forest Cty)	1.0	WOODBURY COUNTY IA	2.0
HARDIN COUNTY IA	2.0	WORTH COUNTY IA	2.0
HOWARD COUNTY IA	2.0		
DELAWARE COUNTY IA	2.0	Franchise Fees:	
DES MOINES COUNTY IA	2.0	BELLEVUE	5.0
DICKINSON COUNTY IA	2.0	BOXHOLM	1.0
DUBUQUE COUNTY IA	2.0	COUNCIL BLUFFS	2.0
FLOYD COUNTY IA	2.0	DUBUQUE	3.0
GREENE COUNTY IA	1.0	ELKADER	5.0
GRUNDY COUNTY IA	2.0	LAMONT	4.0
GUTHRIE COUNTY IA	1.0	MONTICELLO	3.0
		OGDEN	1.0
		STRAWBERRY POINT	2.0

PRESSURE FACTOR IN TOWN
GAS

Ackley	0.9742	Glenwood	0.9810	Onawa	0.9742
Adair	0.9674	Glidden	0.9742	Orleans	0.9640
Anamosa	0.9878	Gowrie	0.9742	Ossian	0.9728
Andrew	0.9871	Grand Junction	0.9803	Paullina	0.9674
Anita	0.9742	Granger	0.9810	Peosta	0.9878
Arion	0.9742	Greene	0.9810	Petersburg	0.9790
Arlington	0.9742	Grimes	0.9810	Pilot Mound	0.9742
Arnolds Park	0.9674	Grundy Center	0.9810	Pocahontas	0.9742
Aurora	0.9810	Guttenberg	0.9946	Postville	0.9742
Baxter	0.9823	Hamburg	0.9810	Primghar	0.9606
Bellevue	0.9946	Hanlontown	0.9742	Ralston	0.9742
Boxholm	0.9810	Harcourt	0.9742	Randall	0.9810
Calmar	0.9728	Hawkeye	0.9742	Readlyn	0.9810
Carter Lake	0.9810	Hopkinton	0.9810	Ridgeway	0.9742
Cedar Falls Rural	0.9864	Ionia	0.9742	Rippey	0.9810
Charles City Rural	0.9572	Jessup	0.9640	Rockford	0.9810
Colesburg	0.9776	Jewel	0.9810	Royal	0.9674
Coon Rapids	0.9742	Joice	0.9728	Saint Ansgar	0.9742
Council Bluffs	0.9810	Kellogg	0.9878	Saint Olaf	0.9905
Crescent	0.9810	Klemme	0.9742	Scranton	0.9742
Cresco	0.9674	Knapp Garden	0.9742	Sidney	0.9810
Cumberland	0.9742	La Motte	0.9851	Spencer	0.9742
Dayton	0.9742	Lake Mills	0.9742	Spirit Lake	0.9606
Decorah	0.9810	Lake View	0.9735	Spirit Lake	0.9640
Delhi	0.9810	Lamont	0.9810	Springville	0.9857
Denison	0.9742	Langworthy	0.9864	Stanhope	0.9783
Dike	0.9810	Laporte City	0.9878	Story City	0.9810
Dow City	0.9742	Lawler	0.9796	Strawberry Pt.	0.9742
Dubuque	0.9939	Lehigh	0.9810	Sumner	0.9810
Dyersville	0.9810	Leland	0.9742	Superior	0.9674
Eagle Center	0.9844	Lewis	0.9756	Tabor	0.9946
Earlville	0.9810	Luana	0.9742	Terril	0.9674
Edgewood	0.9742	Madrid	0.9810	Tipton	0.9878
Elkader	0.9878	Manchester	0.9810	Tripoli	0.9810
Elmerado Estates	0.9742	Maquoketa	0.9878	Vincent	0.9742
Emmons	0.9674	Marble Rock	0.9810	Wahpeton	0.9708
Epworth	0.9803	Martelle	0.9857	Wallingford	0.9674
Estherville	0.9674	Massena	0.9728	Waukon	0.9742
Everly	0.9695	Miles	0.9878	Webster City	0.9810
Farley	0.9742	Milford	0.9667	West Okoboji	0.9708
Farmersburg	0.9878	Mitchell	0.9742	West Union	0.9742
Farnhamville	0.9742	Monona	0.9742	Woodward	0.9810
Fayette	0.9810	Monticello	0.9878	Worthington	0.9844
Fertile	0.9742	New Hampton	0.9742	Zwingle	0.9857
Fonda	0.9749	New Vienna	0.9810		
Forest City	0.9742	Newton	0.9837		
Fostoria	0.9661	Ogden	0.9742		
Fredericksburg	0.9742	Ogden	0.9742		
Garden City	0.9810	Okoboji	0.9708		
Garnavillo	0.9823	Okoboji - Outside	0.9708		

In order to bring all sales base pressures to a standard of 14.73 psi, the above pressure factors are applied to all metered volumes in the corresponding towns.

RATES
GAS

HELD FOR FUTURE USE

RATES GAS

RESERVED FOR FUTURE USE

RATES
GAS

HELD FOR FUTURE USE

RATES
GAS

HELD FOR FUTURE USE

PURCHASED GAS ADJUSTMENT – UNIFORM CLAUSE
GAS

I. Rates Subject to the Purchased Gas Adjustment (PGA) Clause

All gas utility rate schedules shall be subject to a gas cost adjustment; however, since Company purchases gas from different supply sources, gas cost adjustments will be calculated for each pipeline identified below:

Pipelines:
Northern Natural Gas Company
Natural Gas Pipeline Company of America

II. Determination of Purchased Gas Adjustment Amount

For purpose of computing the Purchased Gas Adjustment, the following formula will be used:

$$PGA = \frac{(C \times Rc) + (D \times Rd) + (Z \times Rz)}{S} + Rb + E$$ C

- PGA is the purchased gas adjustment per unit.
- S is the anticipated yearly gas commodity sales volume for each customer classification or grouping.
- C is the volume of applicable commodity purchased or transported for each customer classification or grouping required to meet sales, S, plus the expected lost and unaccounted for volumes.
- Rc is the weighted average of applicable commodity prices or rates, including appropriate hedging tool costs, to be in effect September 1 corresponding to purchases C. C
- D is the total volume of applicable entitlement reservation purchases required to meet sales, S, for each customer classification or grouping. C
- Rd is the weighted average of applicable entitlement reservation charges to be in effect September 1 corresponding to purchases D. C
-
-
- Z is the total quantity of applicable storage service purchases required to meet sales, S, for each customer classification or grouping.
- Rz is the weighted average of applicable storage service rates to be in effect September 1 corresponding to purchased Z.
- Rb is the adjusted amount necessary to obtain the anticipated balance for the remaining PGA year calculated by taking the anticipated PGA balance divided by the forecasted volumes, including storage, for one or more months of the remaining PGA year. C
- E is the per unit over- or under-collection adjustment as calculated under subrule 19.10(7). C

PURCHASED GAS ADJUSTMENT – UNIFORM CLAUSE (Continued)
GAS

III. Application of Calculation
The formula

$$PGA = \frac{(C \times Rc) + (D \times Rd) + (Z \times Rz) + Rb}{S} + E$$ C

identified previously will be calculated separately for each wholesale pipeline supplier and for Directly-Assigned (Joint and Interruptible) and Non-Directly-Assigned (General Service) customers. The Company shall file on or before August 1 of each year a purchased gas adjustment for the 12 month period beginning Sept. 1 of that year. C C

V. Cost Included in the Purchased Gas Adjustment
The cost of gas included in the computation shall consist of all costs properly included in FERC Accounts 800 through 812.

. Frequency of Change
The adjustments under this provision shall be computed and filed annually by August 1 of each year and will project the average cost of gas for the prospective twelve month period beginning September 1 of that year. During the twelve-month period beginning September 1, a change in rate will be reflected whenever a change in the formula identified previously results in an increase or decrease in the new projected effective rate for purchased gas. T D

VI. Annual Reconciliation
The Company shall file a Purchased Gas Adjustment reconciliation between September 1 and October 1 of each year. The Company shall maintain a continuing monthly comparison of the actual cost of gas as shown on the books and records of the Company, exclusive of refunds, and the cost recovery for the same month calculated by multiplying the volumes sold during said month by the currently effective rate for purchased gas and the prior year's reconciliation adjustment. D

For each twelve month period which began September 1 of the previous year, an Actual Cost Adjustment (ACA) shall be developed by dividing the cumulative balance of unrecovered or over-recovered costs by the sales volumes for the prospective twelve-month period beginning September 1. The ACA shall be applied to sales billed for the ten month period beginning November 1.

If the cumulative balance results in a net over-recovery exceeding the "maximum" limit of three percent of the annual cost of purchased gas subject to recovery, the Company shall refund the over-recovery by bill credit, with interest as stated in 19.10(7)b(1) for the time period beginning September 1 of the current year to the date of refund. The annual reconciliation shall include the information on hedging tools identified in IAC 19.10(7). C C C

VII. Treatment of Refunds
In the event a refund is received by the Company from any supplier of natural gas attributable to the cost of gas which has been sold by the Company under the foregoing purchased gas adjustment clause, Company shall file a refund report as stated in 19.10(8). C

PURCHASED GAS ADJUSTMENT – UNIFORM CLAUSE (Continued)
GAS

VII. Supplemental Gas Supply
In the event the Company finds it necessary to supplement its pipeline supply of natural gas by means of peak shaving with propane air, liquefied natural gas or other short term supplemental gas supplies, the associated gas purchase costs will be included in the formula for calculating the Purchased Gas Adjustment.

VIII. Information to be Filed with the Commission
Each Purchased Gas Adjustment will be accomplished by filing an application and will be accompanied by such supporting data and information as the Commission may require.

RATES
GAS

HELD FOR FUTURE USE

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RIDER NO. 1, PURCHASED GAS ADJUSTMENT – UNIFORM CLAUSE
GAS

Purchased Gas Adjustment – Uniform Clause
Information Sheet
Rider No. 1

		Entitlement Chg/Month $	$ / Therm or Per Month
PGA 1	GS		0.57205
PGA 2	SVI / LVI		0.57205
PGA 3	SVF / LVF-Commodity		0.46760
PGA 4	Firm Entitlement – SVF / LVF		1.02300

RATES
GAS

HELD FOR FUTURE USE

RIDER NO. 1D, ISS-2
GAS

1. Applicability: Applicable to all customers served from Northern Natural Gas Company's pipeline including, but not limited to, end users having alternate fuel capability and economic expansion, etc. when such customers have executed an ISS-2 contract with Company.

2. Contract Requirements: In order for this rider to apply, the customer must contract with Company to purchase natural gas from Company to satisfy the customer's energy requirements as specified in the contract for the term of the contract. The term of each contract shall be subject to negotiations between Northern, Company and the individual customer. Where special gas packages are available from the pipeline or other sources that are designated only for certain end use customers these costs will be assigned directly to the specific end use customers. This includes, but is not limited to, Northern Natural Gas Company's Rate Schedule ISS-2. Company will submit a copy of each contract to the Iowa Utilities Board as soon as it is completed. These contracts will go into effect immediately unless and until objected to by the Iowa Utilities Board. Such contracts are specifically subject to requirements of Northern's FERC approved ISS-2 tariff.

3. Rate: The rate for applicable volumes agreed to shall be the rate specified in each contract for ISS-2 Service. Once an ISS-2 rate is agreed to and approved for a customer, the commodity price charged to the customer for gas shall be as indicated in the ISS-2 contract.

4. Term: This rider shall be available for the period July 1, 1988 through June 30, 1989, or until Northern's authority is revoked by the Federal Energy Regulatory Commission. T

RIDER NO. 1E, TEMPORARY RETENTION SERVICE (TRS)
GAS

1. Applicability: Applicable to all customers served by Company having an alternate fuel capability for requirements in excess of 199 Dekatherm per day when such customers have executed a TRS contract amendment with Company.

2. Contract Requirements: In order for this rider to apply, the customer must sign a contract amendment with Company to purchase natural gas from Company to satisfy the customer's energy requirements as specified in the contract amendment for the term of the contract amendment. The term of each contract amendment shall be subject to negotiations between Company and the individual customer, with the term of the contract amendment not to exceed a 60 day period. Company shall submit a copy of each contract amendment to the Iowa State Utilities Board as soon as possible after the amendment is signed by both parties.

   Any customer seeking a TRS contract amendment shall be required to file an affidavit (1) to attest that the customer is able to obtain a burner tip alternate fuel price lower than Company's approved commodity rate, and (2) to attest that the customer would switch to the alternate fuel if the flexible rate is not offered. The affidavit will also identify the alternate fuel supply and set forth the burner tip price of the alternate fuel.

3. Rate: The commodity rate agreed to by Company and the customer for applicable volumes shall be the rate specified in each contract amendment for Temporary Retention Service. Once a TRS rate is established and agreed to by Company and the customer, the commodity price charged to the customer for gas shall be as specified in the TRS contract amendment. The commodity price established must be between floor and ceiling specifications as follows. The floor commodity price is equal to the cost of gas included in the applicable rate schedule, including applicable cost of gas adjustment. The ceiling commodity price is to be the commodity rate in effect per applicable rate schedule, including applicable cost of gas adjustments, approved and on file with the Iowa Utilities Board. TRS rates shall be applicable to commodity rates only. Customers receiving service pursuant to firm or joint firm and interruptible rate schedules shall

RIDER NO. 1E, TEMPORARY RETENTION SERVICE (TRS) (Continued)
GAS

continue to pay applicable demand charges. The customer shall be subject to the provisions of the tariff and the Cost of Gas Adjustment, except that the commodity charge shall be the price indicated in the TRS contract amendment. Company will adjust the margin component of the TRS rate to compensate for gas cost changes occurring during the term of the TRS contract amendment. The gas cost component of the total rate, as well as the margin component, will move upward or downward to reflect changes in Company's cost of gas. In the event increases or decreases in gas cost cause the margin to move downward or upward to the extent the margin would not comply with the floor or ceiling specifications, the TRS contract amendment shall automatically terminate. Customers having a TRS contract amendment will continue to be identified on their present tariff schedule.

4. Cost/Benefit Analysis: In deciding whether to offer a specific discount, Company shall evaluate the individual customer's situation and perform a cost-benefit analysis before offering the discount.

5. Reporting: Semi-annual reports shall be filed with the Board within thirty days of the end of each six months. Information included in the reports shall be as specified in Iowa Adm. Code § 199-19.12(4).

6. Term: As specified in Iowa Adm. Code 199-19.12(3)d, no discount shall be offered for a period longer than five years, unless the Board determines upon good cause shown that a longer period is warranted.

RIDER NO. 1F, SMALL VOLUME TEMPORARY RETENTION SERVICE (SV TRS) (Continued)
GAS

1. Applicability: Applicable to all customers served by Company having an alternate fuel capability for requirements in excess of 24 Dekatherm per day but less than 200 Dekatherm per day when such customers have executed a TRS contract amendment with Company.

2. Contract Requirements: In order for this rider to apply, the customer must sign a contract amendment with Company to purchase natural gas from Company to satisfy the customer's energy requirments as specified in the contract amendment for the term of the contract amendment. The term of each contract amendment shall be subject to negotiations between Company and the individual customer, with the term of the contract amendment not to exceed a 60 day period. Company shall submit a copy of each contract amendment to the Iowa Utilities Board as soon as possible after the amendment is signed by both parties.

   Any customer seeking a TRS contract amendment shall be required to file an affidavit (1) to attest that the customer is able to obtain a burner tip alternate fuel price lower than Company's approved commodity rate, and (2) to attest that the customer would switch to the alternate fuel if the flexible rate is not offered. The affidavit will also identify the alternate fuel supply and set forth the burner tip price of the alternate fuel.

3. Rate: The commodity rate agreed to by Company and the customer for applicable volumes shall be the rate specified in each contract amendment for Temporary Retention Service. Once a TRS rate is established and agreed to by Company and the customer, the commodity price charged to the customer for gas shall be as specified in the TRS contract amendment. The commodity price established must be between floor and ceiling specifications as follows. The floor commodity price is equal to the cost of gas included in the applicable rate schedule, including applicable cost of gas adjustment. The ceiling commodity price is to be the commodity rate in effect per applicable rate schedule, including applicable cost of gas adjustments, approved and on file with the Iowa Utilities Board. TRS rates shall be applicable to commodity rates only. Customers receiving service pursuant to firm or joint firm and interruptible rate schedules shall continue to pay applicable demand charges. The customer shall be subject to the provisions of the tariff and the Cost of Gas Adjustment, except that the commodity charge shall be the price indicated in the TRS contract amendment. Company will adjust the margin component of the TRS rate to compensate for gas cost changes occurring during the term of the TRS contract amendment. The gas cost component of the total rate, as well as the margin component, will move upward or downward to reflect changes in Company's cost of gas. In the event increases or decreases in gas cost cause the margin to move downward or upward to the extent the margin would not comply with the floor or ceiling specifications, the TRS contract amendment shall automatically terminate. Customers having a TRS contract amendment will continue to be identified on their present tariff schedule.

RIDER NO. 1F, SMALL VOLUME TEMPORARY RETENTION SERVICE (SV TRS) (Continued)
GAS

4. Cost/Benefit Analysis: In deciding whether to offer a specific discount, Company shall evaluate the individual customer's situation and perform a cost-benefit analysis before offering the discount.

5. Reporting: Semi-annual reports shall be filed with the Board within thirty days of the end of each six months. Information included in the reports shall be as specified in Iowa Adm. Code § 199-19.12(4).

6. Term: As specified in Iowa Adm. Code 199-19.12(3)d, no discount shall be offered for a period longer than five years, unless the Board determines upon good cause shown that a longer period is warranted.

RIDER NO. 1G, ECONOMIC DEVELOPMENT DISCOUNT/INCENTIVE RATE
GAS

1. Applicability: An Economic Development Discount/Incentive Rate may be offered to any new or existing customer who will increase load in response to a discount or a prospective customer who will initiate operations in response to a discount.

2. Rate: The discount/incentive sales or transportation rate shall be as agreed to between Company and customer. The ceiling is the current approved margin or transportation rate included in the applicable rate schedule. For a retail sales customer, the ceiling rate is to be the commodity rate in effect per applicable rate schedule, including the applicable cost of gas adjustment, approved and on file with the Iowa Utilities Board. The floor transportation rate is zero. For a sales customer, the floor is equal to the cost of gas included in the applicable rate schedule, including the applicable cost of gas adjustment. Discount/incentive rates are applicable to transportation rates, and retail sales commodity and contract demand margins. If applicable, the gas cost component of the total rate will move upward or downward to reflect changes in Company's cost of gas. Discount/incentive rates shall be offered to all of customer's direct competitors.

3. Cost/Benefit Analysis: In deciding whether to offer a specific discount, Company shall evaluate the individual customer's situation and perform a cost-benefit analysis before offering the discount.

4. Reporting: Semi-annual reports shall be filed with the Board within thirty days of the end of each six months. Information included in the reports shall be as specified in Iowa Adm. Code § 199-19.12(4).

5. Term: As specified in Iowa Adm. Code 199-19.12(3)d, no discount shall be offered for a period longer than five years, unless the Board determines upon good cause shown that a longer period is warranted.

RATE SCHEDULE
GAS

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RATES
GAS

To access the Company’s transportation services agreements and related documents, please refer to:

http://www.blackhillsenergy.com/customers/energyrates/. T

RIDER NO. 3, ENERGY EFFICIENCY COST RECOVERY
GAS RATES

		$/Therm	
ECR-1	Residential General Service GS – Tariff Sheet Nos. 3, 4	$ 0.04978	I
ECR-2	Non-Residential General Service GS - Tariff Sheet Nos. 3, 4	$(0.01017)	D
ECR-3	Non-General Service SVI – Tariff Sheet No. 15 SVJ – Tariff Sheet No. 22 LVI – Tariff Sheet Nos. 17, 18, 19, 20 LVJ – Tariff Sheet Nos. 13, 14, 14a ML – Tariff Sheet Nos. 20a, 23, 24	$0.01700	D
ECR-4	Transportation	$ -	

RATES
GAS

HELD FOR FUTURE USE

SMALL VOLUME TRANSPORTATION RATE SCHEDULE

1. Availability: Service under this rate schedule is available to any non-General Service end-use customer who purchases gas supplies that can be transported on a firm and/or interruptible basis by Company. Service hereunder shall be offered on a non-discriminatory firm and/or interruptible basis contingent upon adequate system capacity. A maximum of 1,200 customers will be allowed to elect this service.

2. Applicability. This service shall apply to small volume gas transportation service, which includes a level of firm and/or interruptible gas service. The interruptible gas is subject to interruption at any time upon order of Company. Daily consumption cannot exceed 199 Dekatherm per meter on any day. Customers electing interruptible service must sign an affidavit confirming the customer has an alternate fuel capability or is willing to discontinue gas service during periods of curtailment. If Customer or Company suspect Customer's maximum daily consumption is 200 Dekatherm per day or more, usage will be monitored by the Company to determine whether the Customer qualifies for large volume service. Small volume customers who convert to transportation service will be required to take assignment to pay for, at the option of the Company, firm interstate natural gas pipeline capacity and supplies designated by Company for a period of up to one year.

3. Rate:
   Fixed Rate: Customer Charge - $50 per month per facility for transportation service, plus the applicable sales tariff basic monthly charge. "Facility" shall include all meters serving buildings under common ownership behind the same town border station ("TBS").

   Daily Firm Capacity Charge
   If applicable, is at the rate set forth in customer's regular sales tariff schedule.

   Commodity Charge
   All volumes received by customer hereunder shall be charged a rate equal to the commodity gross margin component of Company's rate then in effect under its sales rate schedule for such customer. Customer is also subject to the Annual Cost Adjustment (ACA), as set forth in TT-1, Rider No. 1, and all charges imposed by the pipeline supplier for transportation service. Additional costs will be assigned as they are authorized by the FERC or state commissions to be charged by Company's pipeline suppliers for transportation services, including, but not limited to, unauthorized overrun charges, take or pay costs, TCR costs, and GRI costs. In addition, all volumes delivered from system supply gas shall be charged the rate set forth in the appropriate Company sales tariff schedule, including the applicable customer charge.

SMALL VOLUME TRANSPORTATION RATE SCHEDULE

Reconnection Charge. An end-user receiving transportation service without system supply reserve service must pay a $20 reconnection charge when such customer requests to return to Company's system supply. T

Taxes - The total bill is subject to state and local taxes.

4. Special Conditions:

A. Customer must have arranged for the purchase of gas other than Company's system supply for delivery to Company's system.

B. Customer shall execute a written contract for transportation service pursuant to this rate schedule containing such terms and conditions as Company reasonably requires. Gas transportation agreements and applicable documents are available at the Company's electronic website,http://www.blackhillsenergy.com/customers/energyrates/. The Company will provide a written copy of the agreements if requested by the customer.

C. Customers must install telemetry equipment or purchase the Balancing Service provided in Section 14 below. Customers must reimburse the Company for the cost incurred by Company to install telemetry equipment and for the cost of any other improvements made by Company in order to provide this transportation service. Customer shall also provide telephonic access and service to this telemetry equipment. The Company will offer financing for periods up to 90 days interest free. The Company will offer financing with interest to a customer to pay for the installation of telemetry equipment for a period of more than 90 days but not more than 12 consecutive months on a non-regulated basis. The telemetry equipment and any other improvements made by the Company shall remain the property of the Company, and will be maintained by the Company.

D. All third party non-regulated suppliers, which are deemed to be Competitive Natural Gas Providers (CNGPs), are subject to the Iowa Utilities Board's rules and regulations governing CNGP's, and must hold an IUB certificate before serving end-users.

E. Company's sales refunds applicable to the period when gas is transported will not be made to transportation customers, except in those instances when such customers have received sales service and may be eligible to receive refunds related to such service.

F. The order of gas delivery for purposes of billing will be as follows:
   1. Customer-owned firm volumes.
   2. Customer-owned interruptible volumes.
   3. Sales gas priced per Company's applicable sales tariffs.

G. Agent Billing – Agency billing may be performed by a competitive natural gas provider ("CNGP") under the following conditions: N
   1. Company will, by September 1, 2009, submit an electronic service that will provide end-user billing information to the CNGP on the bill issuance date. End-use customers will receive a hard copy of the billing.
   2. The CNGP will pay the bill on behalf of the end-use customer by using an automated electronic payment format. All bills must be paid by the due date printed on the bill. All payments must be accompanied by an electronic file listing the individual payment amounts for each end-use customer account.
   3. Multiple customer payments may be combined in the electronic payment format.
   4. In the event an end-user account has a credit balance, the CNGP may not net the credit against the amount due to Company by other customers.
   5. Over and under-billings wil be resolved between the CNGP and the Company.

SMALL VOLUME TRANSPORTATION RATE SCHEDULE (continued)

H. Customer is responsible for ensuring that the gas purchased from a third party is delivered. Customer agrees to curtail the use of gas when the gas purchased from a third party is not delivered to Company's system. Failure to curtail will result in penalties for unauthorized takes per Section 12.

I. Customers may transfer to Transportation Service after giving the Company one month advance notice, and after telemetry equipment, if required, is installed. A transportation customer may only transfer to firm or interruptible sales service if Company is able to arrange adequate additional daily firm capacity and commodity supplies to meet the needs imposed on its system by the Customer, without jeopardizing system reliability or increasing costs for its own Customers. All customers who elect to move to small volume transportation service will be allowed to make this election only in the month of September for service beginning October 1. All customers who elect to move back to sales service will make this election only in the month of April, for sales service beginning May 1. Non-winter peaking customers may move to SVTS in any month.

J. Customers choosing joint rate transportation service may either: (1) purchase both interstate pipeline capacity and Company's distribution system capacity from Company at the rate determined by Company's' tariff, Schedule TT-1, or (2) purchase an unbundled demand service, with the interstate pipeline capacity portion being purchased from a third party, non-regulated supplier and the distribution capacity service for Company's system being purchased from Company at the rate determined by Company's tariff, Schedule TT-1. Transportation will not commence until the Customer files with the Company a completed Service Request Form and all other applicable documentation. Company shall be deemed to have title to transportation gas, as necessary, to arrange interstate pipeline transportation to Company's system.

K. Except as provided under Iowa Adm. Code § 19.13(2) regarding curtailment and interruption, customer has the right to receive one hundred percent (100%) of the gas delivered by it or on its behalf to Company (adjusted for a reasonable volume of lost, unaccounted-for, and company-used gas).

L. Aggregation Service. A Marketer may combine a group of transportation Customers that have the same balancing provisions and are located on the same interstate pipeline system and within the same interstate pipeline operational zone. Customers that purchase the Small Volume Balancing Service in Paragraph 14 cannot be aggregated in the same group as those customers that do not purchase the Small Volume Balancing Service. If the Marketer purchases this aggregation service, the aggregated group will be considered as one Customer for purposes of calculating the daily scheduling penalties and monthly imbalances, i.e., individual Customer nominations and consumption will be summed and treated as if they were one Customer. This does not include aggregation of fixed costs or customer charges. The cost of this aggregation service is $0.04 per Dekatherm of gas delivered to the aggregated group. Revenues received from this service shall be credited to the Company's PGA mechanism.

SMALL VOLUME TRANSPORTATION RATE SCHEDULE (continued)

5. BTU Adjustment: Customer's volumetric billed usage will be adjusted when the BTU content of delivered gas varies from 1,000 BTUs per cubic foot.

6. Nominations:

   A. Requirements. Customers are required to nominate daily. Customers requesting volumes to flow on the first day of any month must contact Company's Gas Control Department via Company's Internet-enabled electronic bulletin board, known as Gas Track Online (http://www.gastrackonline.com), and inform them of the volumes to be transported by receipt point(s) and delivery point(s). First of the month nominations and daily nominations via the Internet are due by 11:30 a.m. Central Time one day before the gas flows. Intra-day nomination for the 2nd through the 31st days of a month will be accepted until 5:00 p.m. Central Time. A confirmed pipeline nomination will also be the accepted on a best effort basis on the day of gas flow.

   B. Special Requirements. All Small Volume sales customers switching to transportation service will be assigned a Maximum Daily Quantity (MDQ) Level, as defined on Sheet GT-4. Under certain circumstances the Company may, at its option, require customers to deliver and confirm its MDQ to the LDC receipt point up to a cumulative 10 days (in addition to interstate pipeline OFO and critical days) during the months of November through March. If MDQ delivery does not occur, then customer must curtail to the level of their confirmed nomination. Confirmation occurs when Aqula Networks receives confirmed nomination from the interstate pipeline. MDQ may be required if:

      1. The interstate pipeline calls a Critical Day Order.
      2. The interstate pipeline calls an Operational Flow Order,
      3. The Company calls a Critical Day Order.
      4. The Company calls an Operational Flow Order.

   In (1) and (2) above, the Customer must, without notice from the Company, deliver its MDQ to LDC receipt point. In (3) and (4) above, the Company will give the Customer 25 hours notice prior to the start of the gas day. If the Customer fails to deliver its MDQ as required in (1), (2), or (3), the Company shall assess a penalty to Customer for each Dekatherm that Customer fails to deliver in an amount equal to the highest daily penalty applicable to the Operational Flow Order or Critical Day, as defined by the interstate pipeline in its tariff. If Company has not called a Critical Day but has issued an Operational Flow Order (4), and customer fails to deliver its MDQ, then Company will assess a penalty to customer in an amount equal to that identified in Paragraph 7 for each Dekatherm that customer failed to deliver.

SMALL VOLUME TRANSPORTATION RATE SCHEDULE (continued)

7. Balancing: To assure Company's system integrity, the customer is responsible for: 1) providing daily scheduling of deliveries which accurately reflect customer's expected consumption, and 2) balancing deliveries to Company's system with volumes consumed at the delivery points.

   A. Balancing and Scheduling Charges: Failure to fulfill these responsibilities will result in Customer incurring balancing and/or scheduling charges as described below.

      1. Daily Scheduling Charges, Normal Days
         a. A tolerance of +/- 5% of confirmed nomination will be applied
         b. For consumption within tolerance, no scheduling charges will be applied.
         c. For consumption outside tolerance, a scheduling charge shall be applied to the volume exceeding tolerance equal to the maximum effective Northern Natural Gas TI rate for the Customer's market area.

      2. Daily Scheduling Charges, System Overrun Limitation. On days that Northern Natural Gas calls a System Overrun Limitation the following charges will be in effect:
         a. For consumption greater than the confirmed nomination, the following charges will be applied:
            1. For consumption up to 105% of confirmed nomination, $1.00 per Dekatherm in excess of confirmed nomination up to 105%.
            2. For consumption greater than 105% of comfirmed nomination, $8.75 per Dekatherm in excess of 105% of confirmed nomination.
         b. For consumption less than the confirmed nomination, there is no charge.

      3. Daily Scheduling Charges, System Underrun Limitation. On days that Northern Natural Gas calls a System Underrun Limitation the following charges will be in effect:
         a. For consumption greater than the confirmed nomination, there is no charge.
         b. For consumption less than the confirmed nomination, $1.00 per Dekatherm.

      4. Daily Scheduling Charges, Critical Days. On days that Northern Natural Gas calls a Critical Day the following charges will be in effect:
         a. For consumption greater than the confirmed nomination, the following charges will be applied:
            1. For consumption up to 102% of confirmed nomination, $15.00 per Dekatherm in excess of confirmed nomination up to 102%.
            2. For consumption greater than 102% up to 105% of confirmed nomination, $22.00 per Dekatherm in excess of 102% up to 105% of confirmed nomination.
            3. For consumption greater than 105% up to 110% of confirmed nomination, $56.50 per Dekatherm in excess of 105% up to 110% of confirmed nomination.
            4. For consumption greater than 110% of confirmed nomination, $113.00 per Dekatherm in excess of 110% of confirmed nomination.
         b. For consumption less than the confirmed nomination, there is no charge.

      5. The charges in this section are subject to change as the pipeline changes its rates. These charges are in addition to any charges by Company, as provided for in Company's tariff, for unauthorized takes of gas when service is interrupted.

SMALL VOLUME TRANSPORTATION RATE SCHEDULE (continued)

B. Monthly Imbalances: The difference between confirmed nominated volumes and actual consumption will be charged or credited to the Customer based on the appropriate Market Index Price (MIP). The basis for the MIP shall be the average weekly prices as quoted for the Ventura and Demarc points in Gas Daily for a 5 week period starting on the first Tuesday of the calendar month for which the MIP is being established and ending on the first or second Monday of the following month, whichever is applicable, to arrive at a five-week period.

1. The MIPs shall be determined as follows:
    a. High MIP: The highest weekly average during the 5-week period for the applicable month, plus pipeline fuel at the effective pipeline fuel rate, plus pipeline commodity at the effective pipeline commodity rate, plus a capacity release value, which will be deemed to be $0.07/Dekatherm.
    b. Low MIP: The lowest weekly average during the 5-week period for the applicable month, plus pipeline fuel at the effective pipeline fuel rate, plus pipeline commodity at the effective pipeline commodity rate.
    c. Average MIP: The average of the weekly averages during the 5-week period for the applicable month, plus pipeline fuel at the effective pipeline fuel rate, plus pipeline commodity at the effective pipeline commodity rate.

2. The cashout mechanism, including tiering, will be applied based on the following Table:

Imbalance Level	Due Company	Due Customer
0% - 3%	High MIP x100%	Low MIP x 100%
For the increment that is greater than 3% up to 5%	High MIP x102%	Low MIP x 98%
For the increment that is greater than 5% up 10%	High MIP x110%	Low MIP x 90%
For the increment that is greater than 10% up to 15%	High MIP x120%	Low MIP x 80%
For the increment that is greater than 15% up to 20%	High MIP x130%	Low MIP x 70%
For the increment that is greater than 20%	High MIP x140%	Low MIP x 60%

3. Imbalances caused by meter error and prior period adjustments will be cashed out at the 0%-3% tier using the average MIP.

SMALL VOLUME TRANSPORTATION RATE SCHEDULE (continued)

B. Monthly Imbalances (continued):

4. Example: If the nominated volume was 100 Dekatherm and the actual consumption was 115 Dekatherm, there is an imbalance of 15 dekatherm due Company. The transportation customer would owe Company the following amount using the above hypothetical high MIP (*):

3 Dekatherm at MIP x 100%	$13.50
2 Dekatherm at MIP x 102%	9.18
5 Dekatherm at MIP x 110%	24.75
5 Dekatherm at MIP x 120%	27.00
	$74.43

(*) A hypothetical price of $4.50 per Dth is used for illustration purposes only.

5. If the pipeline provides an imbalance to storage option, and the transporter has a storage account on the pipeline, Company and the transporter may transfer imbalances to or from pipeline storage accounts, provided certain conditions are met. If the transaction would cause Company's storage account to breach any contractual limitations, or would otherwise cause undue harm to Company's management of its storage accounts, the storage transfer may not be allowed. If there are any charges from the pipeline to effectuate the storage transfer, the customer will be responsible for payment of such actual costs.

8. Pipeline Charges: Any specific charges that Company incurs from the pipeline on behalf of customer will be passed through to that customer. Such charges include but are not limited to those that may be imposed by an applicable pipeline as set forth in paragraphs 7 and 12.

9. System Supply Reserve Service. In order to obtain a firm backup sales service, customer must purchase a sufficient number of daily firm capacity units to cover the desired level of firm sales service. The rate for System Supply Reserve Service will be the daily midpoint of the Gas Daily NNG Ventura Index, plus pipeline fuel, pipeline capacity and commodity charges, plus the monthly customer charge and daily firm capacity charge for the applicable class of sales service. The minimum term for this service is six months. A customer who takes gas in excess of the contracted amount will be subject to balancing and scheduling penalties. If a customer's transportation gas does not arrive on schedule, the customer will be shut off until the transportation gas does arrive, unless the customer has not taken more than its contracted amount of gas, pursuant to System Supply Reserve Service. Revenues collected from the provision of this service will be credited to the overall general system gas cost through Company's PGA mechanism.

SMALL VOLUME TRANSPORTATION RATE SCHEDULE (continued)

10. Right of Refusal: Company shall not be required to transport gas and may discontinue transporting gas when the gas tendered for transportation is of a quality which will adversely impact the commingled gas stream of Company to the extent that the mixed stream is not merchantable natural gas.

11. Payment: The bill is due twenty days after issuance. There shall be a late payment charge of one and one-half percent per month on the unpaid balance.

12. Penalty for Unauthorized Takes When Service is Interrupted or Curtailed: If customer fails to curtail its use of gas hereunder when requested to do so by Company, customer shall be billed at the transportation charge plus the cost of gas Company secures for the customer, plus the greater of either the pipeline daily delivery variance charges or $20 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues related to unauthorized takes will be credited to the Company's PGA. Company may in addition disconnect customer's supply of gas if customer fails to curtail its use thereof when requested by Company to do so.

    Curtailment of transportation volumes will take place according to the priority class, which the end-user would have been assigned if it were purchasing gas from Company. During curtailment, the end-user is entitled to a credit equal to the difference between the volumes delivered to Company and those received by the end-user, adjusted for lost, unaccounted-for and company used gas.

13. Transportation without System Supply Reserve: A customer contracting for service without system supply reserve must acknowledge in writing that it has been made aware by Company of the risks of transporting gas without system supply reserves and accepts the risks.

14. Small Volume Customer Balancing Service: Small volume customers who elect transportation service may purchase Company's Small Volume Balancing Service in lieu of meeting Company's Transportation Tariff requirements for the installation of telemetry and daily scheduling requirements. Customers choosing this daily balancing service must submit a daily nomination to Company for those days the service is used. The special requirements for nominations, found in Paragraph 6B, apply to this service.

    The cost of the service is 7.5¢ per Dekatherm transported on Company's system. Revenues collected from the provision of this service will be credited to the overall general system gas cost through Company's PGA mechanism.

15. General Terms and Conditions: The General Terms and Conditions contained in this tariff shall apply to this rate schedule.

LARGE VOLUME TRANSPORTATION RATE SCHEDULE

1. Availability: Service under this rate schedule is available to any Large Volume non-General Service end-use customer who purchases gas supplies that can be transported on a firm and/or interruptible basis by Company. Service hereunder shall be offered on a nondiscriminatory firm and/or interruptible basis contingent upon adequate system capacity.

2. Applicability: This service shall apply to large volume gas transportation service, which includes a level of firm and/or interruptible gas. The interruptible gas is subject to interruption at any time upon order of Company. Daily consumption must equal or exceed 200 Dekatherm per meter per day at least once during the year. Company will have measuring equipment in place to measure daily consumption. Customers electing interruptible service must sign an affidavit confirming the Customer has an alternate fuel capability or is willing to discontinue gas service during periods of curtailment. Large volume customers who convert to transportation service will be required to take assignment to pay for, at the option of the Company, firm interstate natural gas pipeline capacity and supplies designated by Company for a period of up to one year.

3. Rate:

   Fixed Rate:
   Customer Charge - $150 per month per facility for transportation service, plus the applicable sales tariff basic monthly charge. “Facility” shall include all meters serving buildings under common ownership behind the same town border station (“TBS”).

   Daily Firm Capacity Charge: If applicable, is at the rate set forth in customer’s regular sales tariff schedule.

   Commodity Charge: All volumes received by customer hereunder shall be charged a rate equal to the commodity gross margin component of Company’s rate then in effect under its sales rate schedule for such customer. Customer is also subject to the Annual Cost Adjustment (ACA) as set forth in TT-1, Rider No. 1 and all charges imposed by the pipeline supplier for transportation service. Additional costs will be assigned as they are authorized by the FERC or state commissions to be charged by Company’s pipeline suppliers for transportation services, including but not limited to authorized overrun charges, take-or-pay costs, TCR costs, and GRI costs. In addition, all volumes delivered from system supply gas shall be charged the rate set forth in the appropriate Company’s sales tariff schedule, including the applicable customer charge.

   Reconnection Charge - An end-user receiving transportation service without system supply reserve service must pay a $5 reconnection charge when such customer requests to return toCompany’s system supply.

   Taxes - The total bill is subject to state and local taxes

LARGE VOLUME TRANSPORTATION RATE SCHEDULE (Continued)

A. Customer must have arranged for the purchase of gas other than Company's system supply for delivery to Company's system.

B. Customer shall execute a written contract for transportation service pursuant to this rate schedule containing such terms and conditions as Company reasonably requires. Gas transportation agreements and applicable documents are available at the Company's electronic website, http://www.blackhillsenergy.com/customers/energyrates/. The Company will provide a written copy of the agreements if requested by the customer. T

C. All Large Volume transportation customers must have the Company install telemetry equipment at the customer's expense. Customers must reimburse the Company for the cost incurred by Companyto install telemetry equipment and for the cost of any other improvements made by Company in order to provide this transportation service. Customer will also provide telephonic access and service to this telemetry equipment. The Company will offer financing for periods up to 90 days interest free. The Company will offer financing with interest to a customer to pay for the installation of telemetry equipment for a period of more than 90 days but not more than 12 consecutive months on a non-regulated basis. The telemetry equipment and any other improvements made by the Company shall remain the property of the Company, and will be maintained by the Company.

D. All third party non-regulated suppliers, which are deemed to be Competitive Natural Gas Providers (CNGPs), are subject to the Iowa Utilities Board's rules and regulations governing CNGP's, and must hold an IUB certificate before serving end-users.

E. Company's sales refunds applicable to the period when gas is transported will not be made to transportation customers, except in those instances when such customers have received sales service and may be eligible to receive refunds related to such service.

F. The order of gas delivery for purposes of billing will be as follows:

1. Customer-owned firm volumes.
2. Customer-owned interruptible volumes.
3. Sales gas priced per Company's applicable sales tariffs

G. Customer is responsible for ensuring that the gas purchased from a third party is delivered. Customer agrees to curtail the use of gas when the gas purchased from a third party is not delivered to Company's system. Failure to curtail will result in penalties for unauthorized takes per Section 12.

G. Customer is responsible for ensuring that the gas purchased from a third party is delivered. Customer agrees to curtail the use of gas when the gas purchased form a third party is not delivered toCompany's system. Failure to curtail will result in penalties for unauthorized takes per Section 12.

H. Customers may transfer to Transportation Service after giving the Company one month advance notice, and after telemetry equipment is installed. A firm (joint) transportation service Customer must stay on Transportation Service for twelve months. A transportation customer may only transfer to firm or interruptible sales service if Company is able to arrange adequate additional daily firm capacity and commodity supplies to meet the needs imposed on its system by the Customer, without jeopardizing system reliability or increasing costs for its own Customers. Notwithstanding the provisions of this Section, Customers transporting gas for seasonal non-winter peaking purposes lasting less than six months shall be allowed to transfer to sales service at any time after providing one month written notice, and do not have to be on transportation service for any specific period of time.

I. Customers choosing joint rate transportation service may either: (1) purchase both interstate pipeline capacity and Company's distribution system capacity from Company at the rate determined by Company's tariff, Schedule TT-1, or (2) purchase an unbundled demand service, with the interstate pipeline capacity portion being purchased from a third party, non-regulated supplier and the distribution capacity service for Company's system being purchased from Company at the rate determined by Company's Tariff, Schedule TT-1. Transportation will not commence until the Customer files with the Company a completed Service Request Form and all other applicable documentation. Company shall be deemed to have title to transportation gas, as necessary, to arrange interstate pipeline transportation to Company's system.

J. Except as provided under Iowa Adm. Code § 19.13(2) regarding curtailment and interruption, customer has the right to receive one hundred percent (100%) of the gas delivered by it or on its behalf to Company (adjusted for a reasonable volume of lost, unaccounted-for, and company-used gas).

K. Aggregation Service. A Marketer may combine a group of transportation Customers that have the same balancing provisions and are located on the same interstate pipeline system and within the same interstate pipeline operational zone. If the Marketer purchases the aggregation service, the aggregated group will be considered as one Customer for purposes of calculating the daily scheduling penalties and monthly imbalances, i.e., individual Customer nominations and consumption will be summed and treated as if they were one Customer. This does not include aggregation of fixed costs or customer charges. The cost of this aggregation service is $0.04 per Dekatherm of gas delivered to the aggregated group. Revenues received from this service shall be credited to the Company's PGA mechanism.

a. <u>BTU Adjustment</u>: Customer's volumetric billed usage will be adjusted when the BTU content of delivered gas varies from 1,000 BTUs per cubic foot.

6. <u>Nominations:</u>

LARGE VOLUME TRANSPORTATION RATE SCHEDULE (Continued)

5. BTU Adjustment: Customer's volumetric billed usave will be adjusted when the BTU content of delived gas varies from 1,000 BTUs per cubic foot.

6. Nominations:

A. Customers are required to nominate daily. Custom1ers requesting volumes to flow on the first day of any month must contact Company's Gas Control Department via Company's Internet-enabled electronic bulletin board, known as Gas Track Online (<http://www.gastrackonline.com>), and inform them of the volumes to be transported by receipt point(s) and delivery point(s). First of the month nominations and daily nominations via the Internet are due by 11:30 a.m. Central Time one day before the gas flows. Intra-day nomination for the 2nd through the 31st days of a month will be accepted until 5:00 p.m. Central Time. A confirmed pipeline nomination will also be accepted on a best effort basis on the day of gas flow.

7. Balancing: To assure Company's system integrity, the customer is responsible for: (1) providing daily scheduling of deliveries which accurately reflect customer's expected consumption, and 2) balancing deliveries to Company's system with volumes consumed at the delivery points. These charges are applicable only to Company's town plant customers whose supply requirements could impact other customers and do not apply to Company's large volume mainline customers who are the only customer taking gas at those points. However, each large volume mainline customer must pay for any balancing and scheduling penalties from pipelines that the customer causes Company to incur.

Balancing and Scheduling Charges: Failure to fulfill these responsibilities will result in customer incurring balancing and/or scheduling charges as described below.

A. Balancing and Scheduling Charges: Failure tofulfill these responsiblities will result in Customer incurring balancing and/or scheduling charges as described below.
   1. Daily Scheduling Charges, Normal Days
      a. A tolerance of +/- 5% of confirmed nomination will be applied.
      b. For consumption within tolerance, no scheduling charges will be applied.
      c. For consumption outside tolerance, a scheduling charge shall be applied to the volume exceeding tolerance equal to the maximum effective Northern Natural Gas TI rate for the Customer's market area.
   2. Daily Scheduling Charges, System Overrun Liimitation. On days that Northern Natural Gas calls a System Overrun Limitation, the following charges will be in effect:
      a. For consumtion greater than the confirmed nomination, the following charges will be applied:
         i. For consumption up to 105% of confirmed nomination, $1.00 per Dekatherm in excess of contirm nomination up to 105%.
         ii. For consumption greater than 105% of confirmed nomination, $8.75 per Dekatherm in excess of 105% of confirmed nomination.
      b. For consumption less than the confirmed nomination, there is no charge.
   3. Daily Scheduling Charges, System Underrun Limitation. On days that Northern Natural Gas calls a System Underrun Limitation, the following charges will be in effect:
      a. For consumption greater than the confirmed nomination, there is no charge.
      b. For consumption less than the confirmed nomination, $1.00 per Dekatherm.

LARGE VOLUME TRANSPORTATION RATE SCHEDULE (Continued)

A. Balancing and Scheduling Charges (continued):

4. Daily Scheduling Charges, Critical Days. On days that Northern Natural Gas calls a Critivcal Day, the following charges will be in effect:
   a. For consumption greater than the confirmed nomination, the following charges will be applied:
      i. For consumption up to 102% of confirmed nomination, $15.00 per Dekatherm in excess of confirmed nomination up to 102%.
      ii. For consumption in excess of 102% up to 105% of confirmed nomination, $22.00 per Dekatherm in excess of 102% up to 105% of confirmed nomination.
      iii. For consumption greater than 105% up to 110% of confirmed nomination, $56.50 per Dekatherm in excess of 105% up to 110% of confirmed nomination.
      iv. For consumption greater than 110% of confirmed nomination, $113.00 per Dekatherm in excess of 110% of confirmed nomination.
   b. For consumption less than the confirmed nomination, there is no charge.
5. The charges in this section are subject to change as the pipeline changes its rates. These charges are in addition to any charges by Company, as provided for in Company's tariff, for unauthorized takes of gas when service is interrupted.

B. Monthly Imbalances. The difference between confirmed nominated volumes and actual consumption will be charged or credited to the Customer based on the appropriate Market Idex Price (MIP). The basis for the MIP shall be the average weely prices as quoted for the Ventura and Demarc points in Gas Daily for a 5 week period starting on the first Tuesday of the calendar month for which the MIP is being established and ending on the first or second Monday of the following month, whichever is applicable, to arrive at a five-week period.

1. The MIPs shall be determined as follows:
   a. High MIP: The highest weekly average during the 5-week period for the applicable month, plus pipeline fuel at the effective pipeline fuel rate, plus pipeline commodity at the effective pipeline commodity rate, plus a capacity release value, which will be deemed to be $0.07 / Dekatherm.
   b. Low MIP: The lowest weekly average during the 5-week period for the applicable month, plus pipeline fuel at the effective pipeline fuel rate, plus pipeline commodity at the effective pipeline commodity rate.
   c. Average MIP: The average of the weekly averages during the 5-week period for the applicable month, plus pipeline fuel at the effective pipeline fuel rate, plus pipeline commodity at the effective pipeline commodity rate.

2. The cashout mechanism, including tiering, will be applied based on the following Table:

Imbalance Level	Due Company	Due Customer
0% - 3%	High MIP x 100%	Low MIP x 100%
For the increment that is greater than 3% up to 5%	High MIP x 102%	Low MIP x 98%
For the increment that is greater than 5% up to 10%	High MIP x 110%	Low MIP x 90%
For the increment that is greater than 10% up to 15%	High MIP x 120%	Low MIP x 80%
For the increment that is greater than 15% up to 20%	High MIP x 130%	Low MIP x 70%
For the increment that is greater than 20%	High MIP x 140%	Low MIP x 60%

3. Imbalances caused by meter error and prior period adjustments will be cashed out at the 0% - 3% tier using the average MIP.

B. Monthly Imbalances (continued):

4. Example: If the nominated volume was 100 Dekatherm and the actual consumption was 115 Dekatherms, there is an imbalance of 15 Dekatherm due Company. The transportation customer would owe Company the following amount using the above hypothetical High MIP (*):

3 Dekatherm at MIP x 100%	$13.50
2 Dekatherm at MIP x 102%	$ 9.18
5 Dekatherm at MIP x 110%	$24.75
5 Dekatherm at MIP x 120%	$27.00
	$74.43

(*) A hypothetical price of $4.50 per Dth is used for illustration purposes only.

5. If the pipeline provides and imbalance to storage option, and the transporter has a storage account on the pipeline, Company and the transporter may transfer imbalances to or from pipeline storage accounts, provided certain conditions are met. If the transaction would cause Company's storage account to breach any ontractual limitations, or would otherwise cause undue harm to Company's management of its storace accounts, the storange trtansfer may not be allowed. If there are any charges from the pipeline to effectuate the storage transfer, the customer will be responsible for payment of such actual costs.

8. Pipeline Charges: Any specific charges that Company incurs from the pipeline on behalf of customer will be passed through to that customer. Such charges include but are not limited to those that may be imposed by an applicable pipeline as set forth in paragraphs 7 and 12.

9. System Supply Reserve Service: In order to obtain a firm backup sales service, customer must purchase a sufficient number of daily firm capacity units to cover the desired level of firm sales service. The rate for System Supply Reserve Service will be the daily midpoint of the Gas Daily NNG Ventura Index, plus pipeline fuel, pipeline capacity and commodity charges, plus the monthly customer charge and daily firm capacity charge for the applicable class of sales service. The minimum term for this service is six months. A customer who takes gas in excess of the contracted amount will be subject to balancing and scheduling penalties. If a customer's transportation gas does not arrive on schedule, the customer will be shut off until the transportation gas does arrive, unless the customer has not taken more than its contacted amount of gas, pursuant to System Supply Reserve Service. Revenues collected from the provision of this service will be credited to the overall general system gas cost through Company's PGA mechanism.

10. Right of Refusal: Company shall not be required to transport gas and may discontinue transporting gas when the gas tendered for transportation is of a quality which will adversely impact the commingled gas stream of Company to the extent that the mixed stream is not merchantable natural gas.

11. Payment: The bill is due twenty days after issuance. There shall be a late payment charge of one and one-half percent per month on the unpaid balance.

12. Penalty for Unauthorized Takes When Service is Interrupted or Curtailed: If customer fails to curtail its use of gas hereunder when requested to do so by Company, customer shall be billed at the transportation charge plus the cost of gas Company secures for the customer, plus the greater of either the pipeline daily delivery variance charges or $20 per Dekatherm, for gas used in excess of the volumes of gas to which customer is limited. Revenues related to unauthorized takes will be credited to the Company's PGA. Company may in addition disconnect customer's supply of gas if customer fails to curtail its use thereof when requested by Company to do so. Curtailment of transportation volumes will take place according to the priority class, which the end-user would have been assigned if it were purchasing gas from Company. During curtailment, the end-user is entitled to a credit equal to the difference between the volumes delivered to Company and those received by the end-user, adjusted for lost, unaccounted-for and company used gas.

13. Transportation without System Supply Reserve: A customer contracting for service without system supply reserve must acknowledge in writing that it has been made aware by Company of the risks of transporting gas without system supply reserves and accepts the risks.

14. General Terms and Conditions: The General Terms and Conditions contained in this tariff shall apply to this rate schedule.

RATE SCHEDULE
GAS

Schedule TT-1
Rider No. 1, Town Plant - General Service and Rural

Tariff Rate Sheet No.	Commodity Gross Margin [1] $/Therm	ECR 1 $/Therm	Basic Monthly Charge	Facility/ Transport Charge	Entitlement
3, 50 & 67 (GS-TP and Rural)	0.11635	0.04988	$18.25	$50.00	0.10451
4, 50 & 67 (GS-TP and Rural)	0.11635	0.04987	$18.25	$50.00	0.10451
3, 50 & 67 (Comm/Industrial)	0.11635	(0.01013)	$29.00	$50.00	0.10451
4, 50 & 67 (Comm/Industrial)	0.11635	(0.01013)	$29.00	$50.00	0.10451

[1] The ceiling transportation rate for all General Service and Rural rates is as indicated above. The floor transportation rate for each of theserate schedules is $0/Therm. The flex provision is offered pursuant to Iowa Adm. Code Sec. 199—19.12(476).

Schedule TT-1
Rider No. 1, Town Plant – Small and Large Volume Joint

					Demand Charge		
Tariff Rate Sheet No.	**Commodity Gross Margin [1]**	**ECR 3**	**Basic Monthly Charge**	**Facility/ Transport Charge**	**Margin [2]**	**Entitlement**	**Total Entitlement**
	$/Therm	$/Therm	$	$	$/Therm	$/Therm	$ Chg/ Mo
22 (SVJ)	0.05237	0.01701	75.00	50.00	0.05010	1.02300	1.07310
14 (LVJ)	0.02364	0.01701	200.00	150.00	0.05010	1.02300	1.07310

[1] The ceiling transportation rate for all Small and Large Volume Joint rates is as indicated above. The floor transportation rate for each of theserate schedules is $0/Therm. The flex provision is offered pursuant to Iowa Adm. Code Sec. 199—19.12(476).

[2] The ceiling contract demand margin for all Small and Large Volume Joint rates is as indicated above. The floor contract demand margin is $0/Therm. The flex provision is offered pursuant to Iowa Adm. Code Sec. 199—19.12(476).

RATE SCHEDULE
GAS

TT-1
Rider No. 1
Mainline - Joint

Tariff Rate Sheet No.	Commodity Gross Margin [1]	ECR 3	Basic Monthly Charge	Facility/ Transport Charge	Demand Charge Margin [2]	Demand Charge Entitlement	Total Entitlement
	$/Therm	$/Therm	$	$	$/Therm	$/Therm	$ Chg/ Mo
23 (SVJ)	0.00500	0.01701	75.00	50.00	0.05010	1.02300	1.07310
14a (LVJ)	0.00500	0.01701	200.00	150.00	0.05010	1.02300	1.07310

[1] The ceiling transportation rate for all Mainline Joint rates is as indicated above. The floor transportation rate for each of these rate schedules is $0/Therm. The flex provision is offered pursuant to Iowa Adm. Code 199-19.12(476).

[2] The ceiling contract demand margin for all Mainline Joint rates is as indicated above. The floor contract demand margin is $0/Therm. The flex provision is offered pursuant to Iowa Adm. Code 199-19.12(476).

Schedule TT-1
Rider No. 1, Town Plant – Small and Large Volume Interruptible

Tariff Sheet No.		Commodity Gross Margin [1] $/Therm	ECR 1 $/Therm	Basic Monthly Charge $	Facility/ Transport Charge $
15 (SVI)		0.05237	0.01701	75.00	50.00
17 (LVI)		0.02364	0.01701	200.00	150.00
18 (LVI)	[2]	0.02364	0.01701	600.00	150.00
19 (LVI)		0.00900	0.01701	200.00	150.00
20 (LVI)		0.02364	0.01701	200.00	150.00

[1] The ceiling transportation rate for all Small and Large Volume Interruptible rates is as indicated above. The floor transportation rate for each of theserate schedules is $0/Therm. The flex provision is offered pursuant to Iowa Adm. Code Sec. 199—19.12(476).

[2] Charged for four months only, September through December.

RATE SCHEDULE
GAS

TT-1
Rider No. 1
Mainline – Interruptible

Tariff Rate Sheet No.	**Comm. Gross Margin [1]**	**ECR 3**	**Basic Monthly Charge**	**Facility/ Transport Charge**
	$/Therm	$/Therm	$	$
24 (SVI)	0.00500	0.01701	75.00	50.00
20a (LVI)	0.00500	0.01701	200.00	150.00

[1] The ceiling transportation rate for all Mainline Interruptible rates is as indicated above. The floor transportation rate for each of these rate schedules is $0/Therm. The flex provision is offered pursuant to Iowa Adm. Code 199-19.12(476).

RATE SCHEDULE
GAS

TT-1
Rider No. 1

Firm Transportation is available to any customer served under a Company tariff designation shown on Rider No. 1. The charges for TF-12, TF5, and TFX are set forth below:

	Reservation Fee $/Therm	**Margin** $/Therm	**Total Charge** $/Therm
TF-12	10.2300 [1]	0.05010	10.28010
TF-5	15.1530 [1]	0.05010	15.20310
Field TF	[1]	0.05010	0.05010

[1] Per Northern Natural Gas Company's FERC Gas Tariff Sheets No. 50 and 51.

GAS

Reserved for Future Use

ENVIRONMENTAL PROTECTION RATE (EPR), RIDER NO. 1H
GAS

1. Applicability: An Environmental Protection rate may be offered to a dual fuel customer requesting to satisfy 100% of its energy requirements with a firm gas supply. The EPR is designed to serve those customers who desire to discontinue operating an alternative fuel system which relies on a petroleum-based fuel contained in an underground or above ground tank. The offering of this rate is intended to assist tank owners/operators in eliminating potential pollution hazards posed by petroleum storage tanks.

2. Contract Requirements: In order for this rider to apply, the customer must execute an agreement with Company to purchase natural gas from Company on a firm basis to satisfy the customer's total energy requirements. Company shall submit a copy of each agreement to the Iowa State Utilities Board as soon as the agreement is signed by both parties. In order for this rider to apply, customer shall sign an affidavit to attest that customer's alternative fuel inventory is contained in an aboveground or underground tank and, as a condition of receiving service under this rider, customer shall discontinue operating its alternative fuel burning system. EPR agreements shall be for a three-year period.

3. Rate: The firm commodity rate agreed to by Company and customer for applicable volumes shall be the rate specified in each EPR agreement. Under the terms of the EPR agreement, customer shall pay in three equal increments over a three-year period the differential between the cost of interruptible service on customer's pre-existing rate and the cost of firm service on Company's applicable tariff rate schedule. Customers on EPR agreements shall, in accordance with the provisions of Iowa Administrative Code 199--19.12(476), be required to pay a rate which recovers the total cost of gas. The non-gas portion of the EPR rate shall be increased in three equal increments over a three-year period. At the conclusion of the three-year period specified in the customer's EPR contract, customer's rate shall be exactly equal to the firm service rate specified in Company's applicable tariff rate schedule. The first of three non-gas rate component increases shall be effective thirty days after the customer executes an EPR agreement. Customer's rate shall increase in the manner described above on the anniversary date of the EPR agreement in years two and three. If a non-gas component rate change occurs, as a result of a general rate case or for any other reason, subsequent to customer's execution of an EPR agreement, the rate change shall be applied in equal increments to the years remaining in the EPR agreement.

4. Cost/Benefit Analysis: In deciding whether to offer an EPR, Company shall evaluate the individual customer's situation and perform a cost/benefit analysis before offering the discount.

5. Reporting: Semiannual reports shall be filed with the Board within thirty days of the end of each six months. Information included in the reports shall be as specified in Iowa Administrative Code 199-19.12(4).

ENVIRONMENTAL PROTECTION RATE (EPR), RIDER NO. 1H (Continued)
GAS

Information Sheet - Non-Gas Cost Adjustments

All EPR customers, whose normal requirement does not exceed 199 Dekatherm on peak day, under the terms of the EPR agreement shall be charged the applicable firm General Service rate with the Non-gas cost subject to the following corresponding adjustment.

General Rate Schedule	Sheet No.	Beginning Year 1 $/Therm	Beginning Year 2 $/Therm	Beginning Year 3 $/Therm
GS1	3	(.03882)	(.01941)	0

Appendix G. Detailed Cost-Effectiveness Results

Portfolio Total

Gas

	2014	2015	2016	2017	2018	Total
No of Participants	21,205	21,808	22,437	23,084	23,754	112,288
Savings (therms)	1,090,474	1,124,394	1,159,052	1,181,203	1,217,451	5,772,574
Capacity Savings (peak day therms)	11,469	11,826	12,191	12,425	12,808	60,720
Total Societal Cost	$16,721,288	$17,318,975	$17,970,127	$18,598,412	$19,255,198	$89,864,000
Direct Participant Costs	$10,626,602	$11,021,253	$11,433,091	$11,835,387	$12,250,873	$57,167,207
Direct Utility Costs	$6,094,686	$6,297,722	$6,537,036	$6,763,025	$7,004,325	$32,696,793
Customer Incentives	$3,330,807	$3,451,725	$3,581,479	$3,713,257	$3,851,083	$17,928,352
Dealer Incentives	$37,873	$69,606	$102,324	$135,758	$170,126	$515,687
Administration	$404,525	$414,808	$426,073	$437,351	$449,335	$2,132,092
Program Delivery	$419,764	$419,343	$429,171	$439,256	$449,604	$2,157,137
Evaluation Delivery	$1,265,560	$1,285,572	$1,317,149	$1,332,581	$1,353,236	$6,554,098
Marketing and Training	$370,308	$382,079	$394,914	$407,891	$421,670	$1,976,862
EM&V	$265,849	$274,589	$285,925	$296,932	$309,271	$1,432,566

	Societal	Participant	Utility	RIM
NPV Benefits	$63,535,368	$54,498,857	$37,282,473	$37,279,473
NPV Costs	$60,062,414	$47,354,372	$27,472,760	$63,439,006
Benefit-Cost Ratio	1.06	1.15	1.36	0.59

Cross-Program Marketing, Training, and Adminstration Costs

COSTS	2014	2015	2016	2017	2018	Total
Gas						
No of Participants						-
Savings (therms)						-
Capacity Savings (peak day therms)						-
Total Societal Cost	$360,000	$369,000	$378,225	$387,681	$397,373	$1,892,278
Direct Participant Costs	$0	$0	$0	$0	$0	$0
Direct Utility Costs	$360,000	$369,000	$378,225	$387,681	$397,373	$1,892,278
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$200,000	$205,000	$210,125	$215,378	$220,763	$1,051,266
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$160,000	$164,000	$168,100	$172,303	$176,610	$841,013
EM&V	$0	$0	$0	$0	$0	$0

	Societal	Participant	Utility	RIM
NPV Benefits	$0	$0	$0	$0
NPV Costs	$1,753,473	$0	$1,592,809	$1,592,809
Benefit-Cost Ratio	-	-	-	-

Residential Total

Gas	2014	2015	2016	2017	2018	Total
No of Participants	14,374	14,826	15,294	15,779	16,281	76,555
Savings (therms)	700,504	720,028	737,573	758,435	779,684	3,696,224
Capacity Savings (peak day therms)	7,419	7,628	7,834	8,058	8,287	39,226
Total Societal Cost	12,056,517	$12,472,216	$12,902,783	$13,359,523	$13,829,870	$64,620,909
Direct Participant Costs	8,446,741	$8,744,833	$9,043,298	$9,361,078	$9,685,155	$45,281,106
Direct Utility Costs	$3,609,776	$3,727,383	$3,859,485	$3,998,445	$4,144,715	$19,339,803
Customer Incentives	$2,565,825	$2,652,516	$2,740,965	$2,835,023	$2,933,251	$13,727,580
Dealer Incentives	$34,703	$63,734	$93,347	$123,682	$154,692	$470,157
Administration	$98,713	$99,901	$101,420	$102,986	$104,931	$507,950
Program Delivery	$38,000	$28,000	$28,000	$28,000	$28,000	$150,000
Evaluation Delivery	$529,650	$529,882	$530,126	$530,383	$530,652	$2,650,693
Marketing and Training	$146,254	$150,905	$156,011	$161,339	$167,185	$781,695
EM&V	$196,632	$202,444	$209,616	$217,032	$226,003	$1,051,727

	Societal	Participant	Utility	RIM
NPV Benefits	$42,734,333	$36,121,614	$24,765,939	$24,762,939
NPV Costs	$44,238,172	$37,518,597	$16,250,697	$39,879,617
Benefit-Cost Ratio	0.97	0.96	1.52	0.62

Residential Evaluation Program

RES_EVAL Gas	2014	2015	2016	2017	2018	Total
No of Participants	2,645	2,648	2,652	2,655	2,659	13,259
Savings (therms)	55,034	55,100	55,170	55,243	55,320	275,866
Capacity Savings (peak day therms)	601	601	602	603	603	3,010
Total Societal Cost	$1,250,768	$1,241,616	$1,242,506	$1,243,441	$1,244,422	$6,222,753
Direct Participant Costs	$544,085	$544,639	$545,221	$545,832	$546,474	$2,726,253
Direct Utility Costs	$706,683	$696,976	$697,285	$697,608	$697,948	$3,496,500
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$66,206	$66,235	$66,266	$66,298	$66,331	$331,337
Program Delivery	$38,000	$28,000	$28,000	$28,000	$28,000	$150,000
Evaluation Delivery	$529,650	$529,882	$530,126	$530,383	$530,652	$2,650,693
Marketing and Training	$33,103	$33,118	$33,133	$33,149	$33,166	$165,668
EM&V	$39,724	$39,741	$39,759	$39,779	$39,799	$198,802

	Societal	Participant	Utility	RIM
NPV Benefits	$1,939,823	$3,500,796	$1,323,893	$1,323,893
NPV Costs	$3,316,715	$2,273,149	$2,957,226	$4,305,609
Benefit-Cost Ratio	0.58	1.54	0.45	0.31

Residential Prescriptive Program

RES_PRESC	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	11,279	11,705	12,148	12,605	13,079	60,816
Savings (therms)	553,001	567,732	580,686	596,544	612,784	2,910,748
Capacity Savings (peak day therms)	5,808	5,965	6,120	6,290	6,464	30,648
Total Societal Cost	$8,234,503	$8,529,660	$8,833,557	$9,152,729	$9,482,381	$44,232,829
Direct Participant Costs	$5,815,160	$6,006,003	$6,201,831	$6,407,667	$6,619,769	$31,050,431
Direct Utility Costs	$2,419,343	$2,523,656	$2,631,725	$2,745,061	$2,862,612	$13,182,398
Customer Incentives	$2,115,825	$2,179,516	$2,245,965	$2,316,373	$2,389,851	$11,247,530
Dealer Incentives	$34,703	$63,734	$93,347	$123,682	$154,692	$470,157
Administration	$26,882	$28,041	$29,241	$30,501	$31,807	$146,471
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$107,526	$112,163	$116,966	$122,003	$127,227	$585,884
EM&V	$134,408	$140,203	$146,207	$152,503	$159,034	$732,355

	Societal	Participant	Utility	RIM
NPV Benefits	$33,106,103	$26,995,034	$19,156,045	$19,156,045
NPV Costs	$30,111,482	$25,736,210	$11,062,411	$29,507,452
Benefit-Cost Ratio	1.10	1.05	1.73	0.65

Residential New Construction Program

RES_NC Gas	2014	2015	2016	2017	2018	Total
No of Participants	450	473	495	519	543	2,480
Savings (therms)	92,470	97,196	101,717	106,648	111,580	509,610
Capacity Savings (peak day therms)	1,010	1,062	1,112	1,165	1,219	5,569
Total Societal Cost	$2,571,246	$2,700,940	$2,826,721	$2,963,354	$3,103,067	$14,165,327
Direct Participant Costs	$2,087,496	$2,194,190	$2,296,246	$2,407,579	$2,518,912	$11,504,422
Direct Utility Costs	$483,750	$506,750	$530,475	$555,775	$584,155	$2,660,905
Customer Incentives	$450,000	$473,000	$495,000	$518,650	$543,400	$2,480,050
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$5,625	$5,625	$5,913	$6,188	$6,793	$30,143
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$5,625	$5,625	$5,913	$6,188	$6,793	$30,143
EM&V	$22,500	$22,500	$23,650	$24,750	$27,170	$120,570

	Societal	Participant	Utility	RIM
NPV Benefits	$7,688,407	$5,625,784	$4,286,001	$4,283,001
NPV Costs	$10,809,975	$9,509,238	$2,231,060	$6,066,556
Benefit-Cost Ratio	0.71	0.59	1.92	0.71

Nonresidential Total

Gas

	2014	2015	2016	2017	2018	Total
No of Participants	958	1,023	1,096	1,168	1,242	5,486
Savings (therms)	317,031	330,146	345,936	346,053	359,709	1,698,875
Capacity Savings (peak day therms)	3,253	3,387	3,531	3,529	3,668	17,369
Total Societal Cost	$2,504,976	$2,634,026	$2,763,701	$2,891,400	$3,023,231	$13,817,333
Direct Participant Costs	$1,483,862	$1,563,690	$1,634,991	$1,707,781	$1,782,365	$8,172,689
Direct Utility Costs	$1,021,114	$1,070,336	$1,128,710	$1,183,619	$1,240,866	$5,644,644
Customer Incentives	$761,682	$795,909	$837,214	$874,934	$914,532	$4,184,272
Dealer Incentives	$3,170	$5,872	$8,977	$12,076	$15,434	$45,529
Administration	$59,716	$62,682	$66,147	$69,421	$72,862	$330,827
Program Delivery	$14,814	$15,219	$15,644	$16,091	$16,560	$78,328
Evaluation Delivery	$65,000	$68,250	$71,663	$75,246	$79,008	$359,166
Marketing and Training	$64,053	$67,174	$70,803	$74,250	$77,875	$354,154
EM&V	$52,678	$55,230	$58,262	$61,602	$64,595	$292,368

	Societal	Participant	Utility	RIM
NPV Benefits	$17,704,826	$13,596,434	$10,614,283	$10,614,283
NPV Costs	$8,537,796	$6,757,091	$4,731,073	$15,139,898
Benefit-Cost Ratio	2.07	2.01	2.24	0.70

Nonresidential Evaluation Program

NONRES_EVAL Gas	2014	2015	2016	2017	2018	Total
No of Participants	160	168	176	185	194	884
Savings (therms)	3,203	3,363	3,532	3,708	3,894	17,700
Capacity Savings (peak day therms)	33	34	36	38	40	181
Total Societal Cost	$174,188	$182,897	$192,042	$201,644	$211,726	$962,496
Direct Participant Costs	$77,500	$81,375	$85,444	$89,716	$94,202	$428,236
Direct Utility Costs	$96,688	$101,522	$106,598	$111,928	$117,524	$534,259
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$10,563	$11,091	$11,645	$12,227	$12,839	$58,364
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$65,000	$68,250	$71,663	$75,246	$79,008	$359,166
Marketing and Training	$16,250	$17,063	$17,916	$18,811	$19,752	$89,792
EM&V	$4,875	$5,119	$5,375	$5,643	$5,926	$26,937

	Societal	Participant	Utility	RIM
NPV Benefits	$12,374	$307,305	$10,382	$10,382
NPV Costs	$558,055	$353,838	$447,811	$458,507
Benefit-Cost Ratio	0.02	0.87	0.02	0.02

Nonresidential Prescriptive Program

NONRES_PRESC	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	784	840	904	967	1,031	4,525
Savings (therms)	228,301	238,292	250,801	247,474	257,514	1,222,383
Capacity Savings (peak day therms)	2,325	2,426	2,536	2,497	2,599	12,382
Total Societal Cost	$2,046,446	$2,160,347	$2,274,118	$2,384,599	$2,498,873	$11,364,383
Direct Participant Costs	$1,228,433	$1,300,620	$1,363,898	$1,428,263	$1,494,001	$6,815,215
Direct Utility Costs	$818,012	$859,727	$910,221	$956,336	$1,004,872	$4,549,168
Customer Incentives	$685,682	$718,109	$757,524	$793,259	$830,774	$3,785,349
Dealer Incentives	$3,170	$5,872	$8,977	$12,076	$15,434	$45,529
Administration	$43,053	$45,249	$47,906	$50,333	$52,888	$239,430
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$43,053	$45,249	$47,906	$50,333	$52,888	$239,430
EM&V	$43,053	$45,249	$47,906	$50,333	$52,888	$239,430

	Societal	Participant	Utility	RIM
NPV Benefits	$14,023,125	$10,650,481	$8,204,106	$8,204,106
NPV Costs	$6,968,196	$5,631,502	$3,811,057	$11,784,994
Benefit-Cost Ratio	2.01	1.89	2.15	0.70

Nonresidential Custom Program

NONRES_CUST	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	12	13	13	14	15	66
Savings (therms)	59,280	62,244	65,356	68,624	72,055	327,559
Capacity Savings (peak day therms)	621	652	685	719	755	3,431
Total Societal Cost	$127,528	$133,905	$140,600	$148,151	$155,559	$705,743
Direct Participant Costs	$75,328	$79,095	$83,050	$87,202	$91,562	$416,237
Direct Utility Costs	$52,200	$54,810	$57,551	$60,949	$63,996	$289,506
Customer Incentives	$36,000	$37,800	$39,690	$41,675	$43,758	$198,923
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$3,600	$3,780	$3,969	$4,167	$4,376	$19,892
Program Delivery	$8,100	$8,505	$8,930	$9,377	$9,846	$44,758
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$2,250	$2,363	$2,481	$2,605	$2,735	$12,433
EM&V	$2,250	$2,363	$2,481	$3,126	$3,282	$13,501

	Societal	Participant	Utility	RIM
NPV Benefits	$2,309,255	$1,680,187	$1,566,561	$1,566,561
NPV Costs	$468,735	$343,923	$242,551	$1,827,951
Benefit-Cost Ratio	4.93	4.89	6.46	0.86

Nonresidential New Construction Program

NONRES_NC	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	2	2	2	2	2	10
Savings (therms)	26,247	26,247	26,247	26,247	26,247	131,233
Capacity Savings (peak day therms)	275	275	275	275	275	1,375
Total Societal Cost	$156,814	$156,877	$156,941	$157,006	$157,074	$784,711
Direct Participant Costs	$102,600	$102,600	$102,600	$102,600	$102,600	$513,000
Direct Utility Costs	$54,214	$54,277	$54,341	$54,406	$54,474	$271,711
Customer Incentives	$40,000	$40,000	$40,000	$40,000	$40,000	$200,000
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$2,500	$2,563	$2,627	$2,692	$2,760	$13,141
Program Delivery	$6,714	$6,714	$6,714	$6,714	$6,714	$33,570
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$2,500	$2,500	$2,500	$2,500	$2,500	$12,500
EM&V	$2,500	$2,500	$2,500	$2,500	$2,500	$12,500

	Societal	Participant	Utility	RIM
NPV Benefits	$1,360,072	$958,460	$833,233	$833,233
NPV Costs	$542,811	$427,828	$229,654	$1,068,445
Benefit-Cost Ratio	2.51	2.24	3.63	0.78

Low-Income Total

Gas

	2014	2015	2016	2017	2018	Total
No of Participants	3,224	3,227	3,231	3,233	3,236	16,151
Savings (therms)	34,374	34,824	35,296	35,596	36,046	176,138
Capacity Savings (peak day therms)	376	381	386	389	394	1,925
Total Societal Cost	$1,275,064	$1,306,673	$1,375,735	$1,397,205	$1,428,893	$6,783,570
Direct Participant Costs	$619,500	$634,701	$675,211	$685,345	$700,546	$3,315,303
Direct Utility Costs	$655,564	$671,972	$700,524	$711,859	$728,347	$3,468,267
Customer Incentives	$3,300	$3,300	$3,300	$3,300	$3,300	$16,500
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$41,315	$42,348	$43,407	$44,492	$45,604	$217,167
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$594,410	$609,410	$635,770	$645,770	$660,770	$3,146,129
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$16,539	$16,914	$18,047	$18,297	$18,672	$88,470

	Societal	Participant	Utility	RIM
NPV Benefits	$1,933,715	$3,676,864	$1,111,939	$1,111,939
NPV Costs	$3,353,540	$2,747,919	$2,918,268	$4,040,794
Benefit-Cost Ratio	0.58	1.34	0.38	0.28

Low-Income Weatherization Program

LI_WEATH Gas	2014	2015	2016	2017	2018	Total
No of Participants	110	113	116	118	121	578
Savings (therms)	16,500	16,950	17,400	17,700	18,150	86,700
Capacity Savings (peak day therms)	180	185	190	193	198	947
Total Societal Cost	$1,155,495	$1,186,930	$1,218,387	$1,239,674	$1,271,176	$6,071,662
Direct Participant Costs	$557,370	$572,571	$587,772	$597,906	$613,107	$2,928,726
Direct Utility Costs	$598,125	$614,359	$630,615	$641,768	$658,069	$3,142,936
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$34,375	$35,234	$36,115	$37,018	$37,944	$180,686
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$550,000	$565,000	$580,000	$590,000	$605,000	$2,890,000
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$13,750	$14,125	$14,500	$14,750	$15,125	$72,250
	0	0	0	0	0	

	Societal	Participant	Utility	RIM
NPV Benefits	$1,173,118	$3,009,722	$649,765	$649,765
NPV Costs	$2,948,551	$2,431,627	$2,646,097	$3,300,430
Benefit-Cost Ratio	0.40	1.24	0.25	0.20

Low-Income Energy Education Program

LI_ED Gas	2014	2015	2016	2017	2018	Total
No of Participants	3,000	3,000	3,000	3,000	3,000	15,000
Savings (therms)	9,690	9,690	9,690	9,690	9,690	48,450
Capacity Savings (peak day therms)	106	106	106	106	106	529
Total Societal Cost	$43,860	$43,905	$43,950	$43,997	$44,045	$219,758
Direct Participant Costs	$20,400	$20,400	$20,400	$20,400	$20,400	$102,000
Direct Utility Costs	$23,460	$23,505	$23,550	$23,597	$23,645	$117,758
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$1,785	$1,830	$1,875	$1,922	$1,970	$9,383
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$20,400	$20,400	$20,400	$20,400	$20,400	$102,000
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$1,275	$1,275	$1,275	$1,275	$1,275	$6,375

	Societal	Participant	Utility	RIM
NPV Benefits	$207,325	$238,820	$154,899	$154,899
NPV Costs	$109,308	$85,065	$99,517	$258,214
Benefit-Cost Ratio	1.90	2.81	1.56	0.60

Low-Income Multifamily Efficiency Improvement Initiative Program

LI_MF Gas	2014	2015	2016	2017	2018	Total
No of Participants	1	1	2	2	2	8
Savings (therms)	22	22	44	44	44	177
Capacity Savings (peak day therms)	0	0.23	0.45	0.45	0.45	2
Total Societal Cost	$40,005	$40,069	$77,563	$77,631	$77,700	$312,970
Direct Participant Costs	$25,310	$25,310	$50,620	$50,620	$50,620	$202,479
Direct Utility Costs	$14,695	$14,760	$26,944	$27,011	$27,081	$110,490
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$2,577	$2,642	$2,708	$2,775	$2,845	$13,547
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$11,360	$11,360	$22,720	$22,720	$22,720	$90,879
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$758	$758	$1,516	$1,516	$1,516	$6,064

	Societal	Participant	Utility	RIM
NPV Benefits	$876	$73,673	$627	$627
NPV Costs	$203,396	$162,759	$90,630	$91,275
Benefit-Cost Ratio	0.00	0.45	0.01	0.01

Low-Income Affordable Housing Program

LI_AH
Gas

	2014	2015	2016	2017	2018	Total
No of Participants	3	3	3	3	3	15
Savings (therms)	372	372	372	372	372	1,860
Capacity Savings (peak day therms)	4	4	4	4	4	20
Total Societal Cost	$7,400	$7,405	$7,410	$7,415	$7,421	$37,051
Direct Participant Costs	$3,770	$3,770	$3,770	$3,770	$3,770	$18,848
Direct Utility Costs	$3,630	$3,635	$3,640	$3,646	$3,651	$18,203
Customer Incentives	$3,300	$3,300	$3,300	$3,300	$3,300	$16,500
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$206	$211	$217	$222	$228	$1,084
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$124	$124	$124	$124	$124	$619

	Societal	Participant	Utility	RIM
NPV Benefits	$25,176	$26,893	$13,976	$13,976
NPV Costs	$19,077	$15,719	$15,385	$29,461
Benefit-Cost Ratio	1.32	1.71	0.91	0.47

Weatherization Team

LI_WEATH_TEAMS	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	110	110	110	110	110	550
Savings (therms)	7,790	7,790	7,790	7,790	7,790	38,951
Capacity Savings (peak day therms)	85	85	85	85	85	426
Total Societal Cost	$28,304	$28,364	$28,424	$28,487	$28,551	$142,130
Direct Participant Costs	$12,650	$12,650	$12,650	$12,650	$12,650	$63,250
Direct Utility Costs	$15,654	$15,714	$15,774	$15,837	$15,901	$78,880
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$2,372	$2,431	$2,492	$2,554	$2,618	$12,467
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$12,650	$12,650	$12,650	$12,650	$12,650	$63,250
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$633	$633	$633	$633	$633	$3,163

	Societal	Participant	Utility	RIM
NPV Benefits	$527,221	$327,756	$292,672	$292,672
NPV Costs	$73,209	$52,749	$66,639	$361,414
Benefit-Cost Ratio	7.20	6.21	4.39	0.81

Public Purpose Total

	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	2,650	2,732	2,816	2,904	2,995	14,096
Savings (therms)	38,564	39,396	40,247	41,119	42,011	201,336
Capacity Savings (peak day therms)	421	431	440	449	459	2,200
Total Societal Cost	$524,731	$537,061	$549,682	$562,604	$575,832	$2,749,910
Direct Participant Costs	$76,500	$78,030	$79,591	$81,182	$82,806	$398,109
Direct Utility Costs	$448,231	$459,031	$470,092	$481,421	$493,026	$2,351,801
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$4,781	$4,877	$4,974	$5,074	$5,175	$24,882
Program Delivery	$366,950	$376,124	$385,527	$395,165	$405,044	$1,928,810
Evaluation Delivery	$76,500	$78,030	$79,591	$81,182	$82,806	$398,109
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$0	$0	$0	$0	$0	$0

	Societal	Participant	Utility	RIM
NPV Benefits	$1,162,493	$1,103,946	$790,313	$790,313
NPV Costs	$2,179,433	$330,765	$1,979,913	$2,785,887
Benefit-Cost Ratio	0.53	3.34	0.40	0.28

School-Based Energy Education Program

PP_ED Gas	2014	2015	2016	2017	2018	Total
No of Participants	1,700	1,734	1,769	1,804	1,840	8,847
Savings (therms)	36,550	37,281	38,027	38,787	39,563	190,208
Capacity Savings (peak day therms)	399	407	416	424	432	2,079
Total Societal Cost	$157,781	$160,937	$164,156	$167,439	$170,787	$821,100
Direct Participant Costs	$76,500	$78,030	$79,591	$81,182	$82,806	$398,109
Direct Utility Costs	$81,281	$82,907	$84,565	$86,256	$87,981	$422,991
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$4,781	$4,877	$4,974	$5,074	$5,175	$24,882
Program Delivery	$0	$0	$0	$0	$0	$0
Evaluation Delivery	$76,500	$78,030	$79,591	$81,182	$82,806	$398,109
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$0	$0	$0	$0	$0	$0

	Societal	Participant	Utility	RIM
NPV Benefits	$949,171	$1,013,356	$691,369	$691,369
NPV Costs	$392,108	$330,765	$356,354	$1,063,392
Benefit-Cost Ratio	2.42	3.06	1.94	0.65

Tree Planting Programs

PP_TREES	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	950	998	1,047	1,100	1,155	5,249
Savings (therms)	2,014	2,115	2,220	2,331	2,448	11,129
Capacity Savings (peak day therms)	22	23	24	25	27	122
Total Societal Cost	$141,450	$144,986	$148,611	$152,326	$156,134	$743,508
Direct Participant Costs	$0	$0	$0	$0	$0	$0
Direct Utility Costs	$141,450	$144,986	$148,611	$152,326	$156,134	$743,508
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$0	$0	$0	$0	$0	$0
Program Delivery	$141,450	$144,986	$148,611	$152,326	$156,134	$743,508
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$0	$0	$0	$0	$0	$0

	Societal	Participant	Utility	RIM
NPV Benefits	$213,323	$90,589	$98,943	$98,943
NPV Costs	$688,969	$0	$625,841	$724,778
Benefit-Cost Ratio	0.31	-	0.16	0.14

Iowa Energy Center and Center for Global and Regional Environmental Research

PP_OTH	2014	2015	2016	2017	2018	Total
Gas						
No of Participants	-	-	-	-	-	-
Savings (therms)	-	-	-	-	-	-
Capacity Savings (peak day therms)	-	-	-	-	-	-
Total Societal Cost	$225,500	$231,138	$236,916	$242,839	$248,910	$1,185,302
Direct Participant Costs	$0	$0	$0	$0	$0	$0
Direct Utility Costs	$225,500	$231,138	$236,916	$242,839	$248,910	$1,185,302
Customer Incentives	$0	$0	$0	$0	$0	$0
Dealer Incentives	$0	$0	$0	$0	$0	$0
Administration	$0	$0	$0	$0	$0	$0
Program Delivery	$225,500	$231,138	$236,916	$242,839	$248,910	$1,185,302
Evaluation Delivery	$0	$0	$0	$0	$0	$0
Marketing and Training	$0	$0	$0	$0	$0	$0
EM&V	$0	$0	$0	$0	$0	$0

	Societal	Participant	Utility	RIM
NPV Benefits	$0	$0	$0	$0
NPV Costs	$1,098,356	$0	$997,718	$997,718
Benefit-Cost Ratio	-	-	-	-

Appendix H. Cross-Reference to IUB Rules

Rule	Reference
199—35.8(476) Assessment of potential and energy efficiency plan requirements.	
35.8(1) Assessment of potential and determination of performance standards	
a. Base Case survey projecting annual peak demand and energy use of customers' existing and estimated new energy-using buildings and equipment.	Appendix A, Chapter 3
b. A survey to identify and describe all commercially available energy efficiency measures and their attributes	Appendix A & B
c. A description of the methods and results for any screening or selection process used to identify technically viable energy efficiency measures.	Appendix A
(1) The utility shall explain its elimination of measures from further consideration.	Appendix A, Chapter 4
(2)The utility shall provide an assessment of either annual economic potential or annual phase-in technical potential for peak demand and energy savings from projected adoption of technically viable measures, describing its methods and assumptions.	Appendix A & B
d. An assessment of the annual potential for utility implementation of the following special programs:	
(1) Peak demand and energy savings from programs targeted at qualified low-income customers, including cooperative programs with community action agencies;	Chapter 7, Appendix A, Appendix G
(2) Implementation of tree-planting programs; and	Chapter 8
(3) Peak demand and energy savings from cost-effective assistance to homebuilders and home-buyers in meeting the requirements of the Iowa model energy code.	Chapters 5 & 6
e. An identification of the utility's proposed performance goals for peak demand and energy savings from utility implementation of cost-effective energy efficiency programs and special programs. The utility shall identify annual goals, by energy efficiency program and total plan, for five years subsequent to the year of the filing.	

Rule	Reference
(1) Cost-effectiveness tests.	Chapters 5,6,7,8 & 10 Appendix G
(2) Cost-effectiveness threshold(s).	Chapter 1, Chapter 10
(3) A description of the proposed programs to be implemented, proposed utility Implementation techniques, the number of eligible participants and proposed rates of participation per year, and the estimated annual peak demand and energy savings.	Chapters 5,6,7,8
(4) The budgets or levels of spending for utility implementation of programs, including proposed special programs addressing low-income, tree-planting and home-building assistance measures.	Chapters 5,6,7,8
(5) The rate impacts and average bill impacts, by customer class, resulting from utility implementation of programs.	Chapter 9
f. An optional sensitivity analysis.	NA
35.8(2) Proposed energy efficiency plan, programs, and budget and cost allocation. The utility shall file with the board an energy efficiency plan listing all proposed new, modified, and existing energy efficiency programs. The following information shall be provided:	
a. The analyses and results of cost-effectiveness tests for the plan as a whole and for each program. For the plan as a whole and for each program, the utility shall provide:	Chapters 5,6,7, 8, & 10, Appendix G
(1) Cost escalation rates for each cost component of the benefit/cost test that reflect changes over the lives of the options in the potential program and benefit escalation rates for benefit components that reflect changes over the lives of the options;	Chapter 2
(2) Societal, utility cost, ratepayer impact measure, and participant test benefit/cost ratios; and	Chapters 5,6,7,8 & 10, Appendix G
(3) Net societal benefits.	Chapters 5,6,7,8 & 10, Appendix G
b. Descriptions of each program. If a proposed program is identical to an existing program, the utility may reference the program description currently in effect. A description of each proposed program shall include:	Chapters 5, 6, 7& 8
(1) The name of each program;	Chapters 5, 6, 7 & 8

Rule	Reference
(2) The customers each program targets;	Chapters 5, 6, 7 & 8
(3) The energy efficiency measures promoted by each program;	Chapters 5, 6, 7 & 8
(4) The proposed utility promotional techniques, including the rebates or incentives offered through each program; and	Chapters 5, 6, 7 & 8
(5) The proposed rates of program participation or implementation of measures, including both eligible and estimated actual participants.	Chapters 5, 6, 7 & 8
c. The estimated annual energy and demand savings for the plan and each program for each year the measures promoted by the plan and program will produce benefits. The utility shall estimate gross and net capacity and energy savings, accounting for free riders, take-back effects, and measure degradation.	Chapters 5, 6, 7 & 8, Appendix G
d. The budget for the plan and for each program for each year of implementation or for each of the next five years of implementation, whichever is less, itemized by proposed costs. The budget shall be consistent with the accounting plan required pursuant to sub-rule 35.12(1). The budget may include the amount of the remittance to the Iowa energy center and the center for global and regional environmental research and the alternative energy revolving loan fund. The plan and program budgets shall be categorized into:	Chapters 5, 6, 7 & 8
(1) Planning and design costs;	Chapters 5, 6, 7 & 8
(2) Administrative costs;	Chapters 5, 6, 7 & 8
(3) Advertising and promotional costs;	Chapters 5, 6, 7 & 8
(4) Customer incentive costs;	Chapters 5, 6, 7 & 8
(5) Equipment costs;	Appendix B
(6) Installation costs;	Appendix B
(7) Monitoring and evaluation costs; and	Chapters 5, 6, 7 & 8
(8) Miscellaneous costs.	Chapters 5, 6, 7 & 8
e. The rate impacts and average bill impacts, by customer class, resulting from the plan and each program.	Chapter 9
f. A monitoring and evaluation plan.	Chapters 5, 6, 7 & 8

Rule	Reference
35.8(9) Coordination with other utilities and participation in plan preparation. The utility shall provide the following reports:	
a. A report which explains the results of attempts to coordinate energy efficiency programs	Chapter 1
b. A report on the participation of interested persons in the preparation of the assessment of potential and energy efficiency plan	Appendix C
35.8(10) Pilot projects. Pilot projects may be included as a program, if justified by the utility. Pilot projects shall explore areas of innovative or unproven approaches, as provided in Iowa Code section476.1. The proposed evaluation procedures for the pilot project shall be included.	NA
199—35.10(476) Additional requirements for gas utilities. In addition to the requirements of rule 35.8(476), a plan for a gas utility shall include the following information:	
35.10(1) Forecast of demand and transportation volumes.	
a. A statement in numerical terms of the utility's current 12-month and 5-year forecasts of total annual throughput and peak day demand, including reserve margin, based on the PGA year by customer class. The forecasts shall not include the effects of the proposed energy efficiency programs in sub-rule 35.8(8), but shall include the effects to date of current ongoing utility energy efficiency programs.	Chapter 2, Appendix E
b. A statement in numerical terms of the utility's current 12- month and five year forecast of highest peak demand day and annual throughput for the past five years by customer class.	Chapter 2, Appendix E
c. A comparison of the forecasts made for the preceding five years to the actual and weather-normalized peak day demand and annual throughput by customer class including an explanation of the weather-normalization procedure.	Appendix E
d. A forecast of the utility's demand for transportation volume for both peak day demand and annual throughput for each of the next five years. .	Appendix E
e. The existing contract deliverability by supplier, contract and rate schedule for the length of each contract.	Appendix E

Rule	Reference
f. An explanation of all significant methods and data used, as well as assumptions made, in the current five-year forecast(s). The utility shall file all forecasts of variables used in its demand and energy forecasts. If variables are not forecasted, the utility shall indicate all sources of variable inputs.	Appendix E
g. A statement of the margins of error for each assumption or forecast.	Appendix E
h. An explanation of the results of the sensitivity analysis performed by the utility, including a specific statement of the degree of sensitivity of estimated need for capacity to potential errors in assumptions, forecasts, and data.	Appendix E
35.10(2) Capacity surpluses and shortfalls.	Appendix E
35.10(3) Supply options.	
a. The year the option would be needed.	Appendix E
b. The type of option.	Appendix E
c. The net peak day capacity.	Appendix E
d. The estimated future capacity costs per dth or Mcf of peak day demand of the options.	Appendix E
e. The estimated future energy costs per dth or Mcf of each option in current dollars.	Appendix E
f. A description of the method used to estimate future costs.	Appendix E
35.10(4) Avoided capacity and energy costs.	
a. Avoided capacity costs.	Chapter 2, Appendix D
b. Avoided energy costs	Chapter 2, Appendix D