Question:

On page 6 of Daniel J. Nikolich's Direct Testimony, Mr. Nikolich states, "Based upon New York Mercantile Exchange futures as of June 15, 2006, wholesale prices of natural gas are expected to increase above $10.00 per dekatherm again next winter." NYMEX natural gas futures have recently declined materially. Provide an analysis of how this decline will influence the Company's forecasted revenues, cost of gas, projected usage, income taxes, excise tax, TRA inspection fee, other taxes and storage gas balances.

Response:

Please see attached schedules.

Summary of Adjustments
to Initial Filing

	Increase/(Decrease)	
Revenues, Gas Costs and Margin		
Revenues	(8,387,533)	
Gas Costs	(8,625,718)	
Margin	238,185	**A/**
Cost of Service		
TRA Inspection Fee	(18,000)	**B/**
Income Taxes (Federal and Excise)	121,684	**D/**
Rate Base		
Stored Gas Inventory	(1,555,176)	**C/**
Lead Lag Requirement	(57,818)	**D/**

A/ Refer to attached schedule

B/ $9,000,000 decrease in revenues multiplies by .2%

C/ The above adjustment represents the same amount as proposed by the CAPD. The amount proposed by the CAPD was based on updated information provided by CGC, which included NYMEX prices as of 9/26/06.

D/ Calculated based on adjustments in A/, B/ and C/.

Note - the above adjustments do not include the costs associated with the ECP. This impact was provided in response to TRA 2-48 and TRA 3-51.

CHATTANOOGA GAS COMPANY
Pro Forma Revenue Calculations

	As Filed in Exhibit PGB-1			Updated With Recent Wholesale Prices		
	[5] Attrition Period Billing Determinates	[6] Current Rates	[7] Attrition Period Current Margin	[5] Attrition Period Billing Determinates	[6] Current Rates	[7] Attrition Period Current Margin
OTHER REVENUE						
# Turn On	8,918	$15.00	$133,770	8,918	$15.00	$133,770
# Meter Set	1,784	$25.00	$44,600	1,784	$25.00	$44,600
# Returned Checks	717	$20.00	$14,340	717	$20.00	$14,340
# Reconnects	2,456	$50.00	$122,800	2,456	$50.00	$122,800
# Seasonal Reconnects	253	$50.00	$12,650	253	$50.00	$12,650
Late Payment			$428,951			$428,951
Damage Billing			$93,265			$93,265
Jobbing			$1,704			$1,704
Total Other Revenue			$852,080			$852,080
FIRM BASE MARGIN						
Residential						
Winter Bills	321,541	$7.50	$2,411,560	321,541	$7.50	$2,411,560
Summer Bills	311,888	$7.50	$2,339,160	311,888	$7.50	$2,339,160
Winter therms Step 1	7,474,950	$0.29385	$2,196,510	7,632,580	$0.29385	$2,242,830
Winter therms Step 2	6,087,760	$0.20265	$1,233,680	6,232,670	$0.20265	$1,263,050
Winter therms Step 3	16,876,090	$0.17732	$2,992,470	17,349,850	$0.17732	$3,076,480
Total Winter	30,438,800			31,215,100		
Summer therms Step 1	3,902,070	$0.21279	$830,320	3,899,520	$0.21279	$829,780
Summer therms Step 2	759,740	$0.15199	$115,470	759,110	$0.15199	$115,380
Summer therms Step 3	602,590	$0.04560	$27,480	602,070	$0.04560	$27,450
Total Summer	5,264,400			5,260,700		
Total Residential	35,703,200		$12,146,650	36,475,800		$12,305,690
Multi-Family Housing (R-4)						
Winter Units Bills	1,110	$6.00	$6,660	1,110	$6.00	$6,660
Summer Units Bills	1,110	$6.00	$6,660	1,110	$6.00	$6,660
Winter therms	61,243	$0.18311	$11,214	61,243	$0.18311	$11,214
Summer therms	20,570	$0.16277	$3,348	20,570	$0.16277	$3,348
Total Multi-Family Housing (R-4)	81,813		$27,882	81,813		$27,882
Total Commercial						
Winter Bills	50,702	$20.00	$1,014,030	50,702	$20.00	$1,014,030
Summer Bills	48,618	$15.00	$729,270	48,618	$15.00	$729,270
Winter therms Step 1	18,656,004	$0.27667	$5,161,560	19,332,495	$0.27667	$5,348,720
Winter therms Step 2	2,011,030	$0.25253	$507,850	2,085,909	$0.25253	$526,750
Winter therms Step 3	3,304,240	$0.24599	$812,810	3,426,595	$0.24599	$842,910
Winter therms Step 4	2,825,426	$0.12727	$359,590	2,936,801	$0.12727	$373,770
Total Winter	26,796,700			27,781,800		
Summer therms Step 1	6,871,355	$0.21722	$1,492,600	6,859,800	$0.21722	$1,490,090
Summer therms Step 2	832,266	$0.17244	$143,520	830,896	$0.17244	$143,280
Summer therms Step 3	1,279,021	$0.16077	$205,630	1,276,920	$0.16077	$205,290
Summer therms Step 4	922,358	$0.12727	$117,390	920,784	$0.12727	$117,190
Total Summer	9,905,000			9,888,400		
Total Commercial	36,701,700		$10,544,250	37,670,200		$10,791,300
Proposed Commercial C-1						
Winter Bills	40,014	$20.00	$800,271	40,014	$20.00	$800,271
Summer Bills	37,922	$15.00	$568,827	37,922	$15.00	$568,827
Winter therms Step 1	5,245,800	$0.27667	$1,451,355	4,703,400	$0.27667	$1,301,290
Winter therms Step 2		$0.25253	$0		$0.25253	$0
Winter therms Step 3		$0.24599	$0		$0.24599	$0
Winter therms Step 4		$0.12727	$0		$0.12727	$0
Total Winter						

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	As Filed in Exhibit PGB-1			Updated With Recent Wholesale Prices		
	[5] Attrition Period Billing Determinates	[6] Current Rates	[7] Attrition Period Current Margin	[5] Attrition Period Billing Determinates	[6] Current Rates	[7] Attrition Period Current Margin
Summer therms Step 1	510,800	$0.21722	$110,956	525,100	$0.21722	$114,062
Summer therms Step 2		$0.17244	$0		$0.17244	$0
Summer therms Step 3		$0.16077	$0		$0.16077	$0
Summer therms Step 4		$0.12727	$0		$0.12727	$0
Total Summer						
Proposed Commercial C-1	5,756,600		$2,931,409	5,228,500		$2,784,450
Proposed Commercial C-2						
Winter Bills	10,688	$20.00	$213,760	10,688	$20.00	$213,760
Summer Bills	10,696	$15.00	$160,440	10,696	$15.00	$160,440
Winter therms Step 1	13,410,204	$0.27667	$3,710,201	14,629,095	$0.27667	$4,047,432
Winter therms Step 2	2,011,030	$0.25253	$507,845	2,085,909	$0.25253	$526,755
Winter therms Step 3	3,304,240	$0.24599	$812,810	3,426,595	$0.24599	$842,908
Winter therms Step 4	2,825,426	$0.12727	$359,592	2,936,801	$0.12727	$373,767
Total Winter						
Summer therms Step 1	6,360,555	$0.21722	$1,381,640	6,334,700	$0.21722	$1,376,024
Summer therms Step 2	832,266	$0.17244	$143,516	830,896	$0.17244	$143,280
Summer therms Step 3	1,279,021	$0.16077	$205,628	1,276,920	$0.16077	$205,290
Summer therms Step 4	922,358	$0.12727	$117,389	920,784	$0.12727	$117,188
Total Summer						
Total Proposed Commercial C-2	30,945,100		$7,612,821	32,441,700		$8,006,843
Commercial T-3						
Winter Bills	12	$20.00	$240	12	$20.00	$240
Summer Bills	12	$15.00	$180	12	$15.00	$180
Winter therms Step 1	36,000	$0.27667	$9,960	36,000	$0.27667	$9,960
Winter therms Step 2	24,000	$0.25253	$6,060	24,000	$0.25253	$6,060
Winter therms Step 3	113,005	$0.24599	$27,800	113,005	$0.24599	$27,800
Winter therms Step 4	66,065	$0.12727	$8,410	66,065	$0.12727	$8,410
Total Winter						
Summer therms Step 1	36,000	$0.21722	$7,820	36,000	$0.21722	$7,820
Summer therms Step 2	24,000	$0.17244	$4,140	24,000	$0.17244	$4,140
Summer therms Step 3	115,200	$0.16077	$18,520	115,200	$0.16077	$18,520
Summer therms Step 4	26,900	$0.12727	$3,420	26,900	$0.12727	$3,420
Total Summer						
Total T-3			$86,550			$86,550
Total Firm Base Revenue			$22,805,332			$23,211,422
INDUSTRIAL BASE REVENUE						
I1/T2 Industrial						
Bills	276	$300	$82,800	276	$300	$82,800
Demand Units (Dths)	105,456	$3.00	$316,368	105,456	$3.00	$316,368
Step 1 Dths	401,463	$0.89450	$359,109	401,463	$0.89450	$359,109
Step 2 Dths	467,674	$0.76440	$357,490	467,674	$0.76440	$357,490
Step 3 Dths	477,049	$0.43350	$206,801	477,049	$0.43350	$206,801
Step 4 Dths	542,963	$0.26640	$144,645	542,963	$0.26640	$144,645
Total I1/T2	1,889,149		$1,467,213	1,889,149		$1,467,213
I1/T2 + T1 Industrial						
Bills	180	$300	$54,000	180	$300	$54,000
Demand Units (Dths)	47,592	$3.00	$142,776	47,592	$3.00	$142,776
Step 1 Dths	270,000	$0.89450	$241,515	270,000	$0.89450	$241,515

	As Filed in Exhibit PGB-1			Updated With Recent Wholesale Prices		
	[5] Attrition Period Billing Determinates	[6] Current Rates	[7] Attrition Period Current Margin	[5] Attrition Period Billing Determinates	[6] Current Rates	[7] Attrition Period Current Margin
Step 2 Dths	404,113	$0.76440	$308,904	404,113	$0.76440	$308,904
Step 3 Dths	716,077	$0.43350	$310,420	716,077	$0.43350	$310,420
Step 4 Dths	214,343	$0.26640	$57,101	214,343	$0.26640	$57,101
Total I1/T2 + T1	1,604,533		$1,114,716	1,604,533		$1,114,716
L1 Industrial						
Bills	12	$300	$3,600	12	$300	$3,600
Step 1 Dths	18,000	$0.89450	$16,101	18,000	$0.89450	$16,101
Step 2 Dths	27,532	$0.76440	$21,045	27,532	$0.76440	$21,045
Step 3 Dths	6,867	$0.43350	$2,977	6,867	$0.43350	$2,977
Step 4 Dths	0	$0.26640	$0	0	$0.26640	$0
Total L1	52,398		$43,723	52,398		$43,723
T1 Industrial						
Bills	300	$300	$90,000	300	$300	$90,000
Step 1 Dths	372,038	$0.89450	$332,788	372,038	$0.89450	$332,788
Step 2 Dths	527,330	$0.76440	$403,091	527,330	$0.76440	$403,091
Step 3 Dths	867,470	$0.43350	$376,048	867,470	$0.43350	$376,048
Step 4 Dths	1,000,983	$0.26640	$266,662	1,000,983	$0.26640	$266,662
Total T1	2,767,820		$1,468,589	2,767,820		$1,468,589
SS-1 Industrial						
Bills	60	$300	$18,000	60	$300	$18,000
Step 1 Dths	78,937	$0.89450	$70,609	78,937	Negotiated	
Step 2 Dths	130,000	$0.76440	$99,372	130,000	Negotiated	
Step 3 Dths	509,478	$0.43350	$220,859	509,478	Negotiated	
Step 4 Dths	716,167	$0.26640	$190,787	716,167	Negotiated	
Total SS-1	1,434,583		$563,003	1,434,583		$563,003
Special Contract Industrial						
Bills	12	$3,500	$42,000	12	$3,500	$42,000
Demand Units (Dths)	120	$3.00	$360	120	$3.00	$360
Step 1 Dths	18,000	$0.89450	$14,561	18,000	$0.03920	$706
Step 2 Dths	30,000	$0.76440	$20,756	30,000	$0.03920	$1,176
Step 3 Dths	132,000	$0.43350	$52,017	132,000	$0.03920	$5,174
Step 4 Dths	428,530	$0.26640	$104,424	428,530	$0.03920	$16,798
Total Special Contract	608,530		$234,119	608,530		$66,214
Total Industrial Margin			$4,891,362			$4,723,457
TOTAL MARGIN			$28,548,775			$28,786,960
MARGINS LESS "OTHER REVENUE"			$27,696,695			$27,934,880
TOTAL REVENUE (INCLUDING GAS COSTS)			$122,084,127			$113,696,594

Question:

Provide a schedule in the format of Exhibit CAPD-1, Schedule 2, documenting CGC's forecast for the twelve months ending December 31, 2007. All Phase II issues should be removed.

Response:

Please see attached schedule.

Line #	Description	CGC Forecast Prefiled Direct Testimony	Adjustment to Exclude ECP Costs (Phase II)	CGC Forecast Excluding ECP Costs (Phase II)
1	Revenues - Sales and Transportation	122,084,127	-	122,084,127
2	Cost of Gas	94,387,432	-	94,387,432
3	Base Revenues	27,696,695	-	27,696,695
4	Forfeited Discount Revenues	428,951	-	428,951
5	Other Revenues	423,129	-	423,129
6	AFUDC	247,000	-	247,000
7	Operating Margin	28,795,775	-	28,795,775
8	Labor	1,957,671	-	1,957,671
9	Long Term Incentive Pay ("LTIP")	261,000	-	261,000
10	Uncollectible Expense	126,670	-	126,670
11	Energy Conservation Plan	738,980	(738,980)	-
12	Other Operations & Maintenance Expense	8,626,766	-	8,626,766
13	Total Operations and Maintenance Expense	11,711,087	(738,980)	10,972,107
14	Interest on customer deposits	123,850	-	123,850
15	Depr. And Amort. Expense	5,812,351	-	5,812,351
16	Taxes Other than Income Taxes	4,079,006	-	4,079,006
17	Income Taxes	1,258,384	290,170	1,548,554
18	Total Operating Expenses	22,984,679	(448,808)	22,535,870
19	Net Operating Income	5,811,096	448,808	6,259,905
20	Rate Base			
21	Gas Plant in Service	180,219,191	-	180,219,191
22	Construction Work in progress	5,026,589	-	5,026,589
23	Materials and supplies/Storage Gas	24,483,680	-	24,483,680
24	Working Capital	(1,303,073)	(23,615)	(1,326,688)
25	Total	208,426,387	(23,615)	208,402,772
26	Deductions:			
27	Accumulated Depreciation	83,137,986	-	83,137,986
28	Contributions and Advances in Aid of Const.	2,187,929	-	2,187,929
29	Accumulated Deferred Income Taxes	14,864,320	-	14,864,320
30	Total	100,190,234	-	100,190,234
31	Rate Base (Line 25-Line 30)	108,236,153	(23,615)	108,212,538
32	Rate of Return	5.37%		5.78%
33	Fair Rate of Return	8.64%		8.64%
34	Deficient (Excess) Rate of Return	3.27%		2.85%
35	Deficient (Excess) NOI	3,535,960		3,085,111
36	Gross Revenue Expansion Factor	1.64509		1.64509
37	Revenue Deficiency (Surplus)	5,816,974		5,075,287

Question:

In regards to Company's exhibit, PGB-1, please explain and show the calculations for columns [2], [3], and [4].

Response:

Please see the Company's response to TRA DR 55 for the electronic Excel spreadsheet for Exhibit PGB-1 that includes all formulas and calculations for columns [2], [3], and [4].

The Company's methodology for producing Exhibit PGB-1 is to begin with Test Year Period actual billing determinates (column [1]), normalize them for the effects of weather and gas price (column [2] and [3]), and then growth them for changes in customer counts and changes in usage (column [4]) to arrive at the forecasted Attrition Year Period billing determinates (column [5]).

The normalization process for the Test Year Period consists of adjusting customer usage to what it would have been under normal weather and gas price conditions. The normalization process was done through linear regression analysis as described in the pre-filed testimony of Phil Buchanan. The results of the normalization process are displayed in column [3] labeled "Normalized", with column [2] simply being the net change between the Test Period Actual billing determinates in column [1] and the Normalized Test Year Period billing determinates in column [3].

After the Test Year Period usage was normalized for weather and gas prices, the number of customers in each customer class were increased/decreased from those in the 2005 Test Year Period to forecast the number of customers in the 2007 Attrition Year Period. The normalized use per customer was then applied to the customer forecast to forecast usage in the Attrition Year Period. The results of the forecast of customers and usage for the Attrition Year Period are displayed in Column [5] labeled "Attrition Period Billing Determinates", with column [4] labeled "Growth Adjustment" simply being the net change between Normalized Test Year Period billing determinates in column [3] and Attrition Period billing determinates in column [5].

Question:

Please reconcile the number of bills and volumes listed in column [1] of Company's exhibit PGB-1 for Multi-Family Housing, Commercial T-3, and all industrial categories with Industrial and Other categories amounts provided on report 3.03 submitted to the Authority for the months January 2005 through December 2005.

Response:

The data in the Company's Exhibit PGB-1 regarding Commercial T-3 and all industrial categories are based on actual monthly volumes used at the individual customer level for the period of January 2005 through December 2005. The customers' volumes and number of customers are then aggregated at the customer class level. The customer class each customer is associated with is consistent with the customer class that each customer is receiving service as of the filing date of the Company in this case. The annual number of bills and volumes are then reported on Exhibit PGB-1 and used as the basis for the industrial forecast.

The data for the Industrial and Other categories reported on the 3.03 report aggregate usage and number of customers in a manner consistent with the methodology used to account for the revenues received from the different types of service. Instead of volumes and number of customers being aggregated at the customer class level, consistent with Exhibit PGB-1, the volumes and number of customers are aggregated by firm and interruptible sales service and firm and interruptible transportation service. Therefore, there is an inherent mismatch in the way volumes and numbers of bills are aggregated and reported on Exhibit PGB-1 and the monthly 3.03 reports.

In June 2005, industrial customers elected to be served as either sales customers or transportation customers for the upcoming year. Prior to June 2005, customers could receive sales and transportation service in the same month. The monthly 3.03 reports reflect the volumes related to the type of service each customer was receiving in that month. In other words, a portion of a customer's usage could be reported on the 3.03 report as sales volumes and a portion could be reported as transportation volumes. The Company's Exhibit PGB-1 is based on each individual customers monthly usage and is aggregated at their current customer class level for the entire 2005 period.

In June 2005, the Company changed billing systems to better accommodate the changes to the industrial class approved in the last rate case. Source data for the 3.03 reports changed, and as a result, some source data was incomplete when reported.

The "Other" category of the 3.03 report consists of data for the Multi-Family customer class. Billing problems for the two Multi-Family customers (that include a total of 185 apartments) were encountered in June and July 2005 as they moved from the industrial billing system to the Company's CIS system. As a result, the customers were not billed volumetric charges for several months, but instead billed in subsequent months. The actual billed volumes were reported on the 3.03 reports, while the volumes in the Company's Exhibit PGB-1 were adjusted to reflect proper and normal billing. Exhibit PGB-1 reports the number of annual billing units (185 apartments times 12), while the 3.03 report reflects the two customers.

Regarding the T-3 customer class, 2 customers began receiving service under this customer class in June 2005. The number of bills reported on the Company's Exhibit PGB-1 represent the number of bills sent from June 2005 through December 2005 (or 2 customers times 7 months). On the 3.03 report, the number of T-3 customers each month is included in the "Industrial" category, as these customers receive firm transportation service. The volumes reported in the Company's Exhibit PGB-1 represent the volumes, in therms, billed to the two customers from June 2005 through December 2005. On the 3.03 report, T-3 customer class volumes are included in the "Industrial" category.

It is the Company's intent to continue to review the 3.03 reports for 2005 and submit revisions as necessary in order to more accurately reflect customer usage and number of customers for the months that source data may have been incomplete.

Question:

Please provide documentation verifying the amounts in column [1] for Company's exhibit PGB-1 for Other Revenue.

Response:

Please see the attached Schedule TRA DR 54 for the calculation of the amounts for the charges listed in column [1] of the Company's exhibit PGB-1 for Other Revenue. The amount for each charge was calculated by dividing the monthly revenue for each charge, as recorded on the income statement, by each charge's tariff rate. The sum of the monthly amounts for each charge type is displayed in column [1].

Chattanooga Gas Company
Calculation of Other Revenue Billing Determinates

Other Revenue *	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005 Total
Turn On	$10,118	$10,078	$11,646	$7,173	$9,043	$9,791	$9,827	$10,092	$8,893	$9,727	$22,326	$15,264	$133,978
Meter Set	$4,575	$4,475	$3,193	$2,229	$2,450	$2,700	$2,729	$2,473	$2,120	$3,987	$5,161	$5,244	$41,334
Returned Check	$1,160	$2,080	$2,180	$1,660	$1,160	$500	$1,160	$740	$740	$560	$780	$880	$13,600
Reconnect Charge	$8,762	$13,843	$13,316	$11,774	$14,251	$10,797	$7,921	$6,978	$7,815	$11,845	$22,524	$6,883	$136,710
Seasonal Reconnect Charge	$550	$250	$109	-$9	$150	$50	$219	$145	$532	$2,513	$6,892	$1,311	$12,712

* *From Income Statement*

Calculation of Billing Determinates

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005 Total
Turn On	$10,118	$10,078	$11,646	$7,173	$9,043	$9,791	$9,827	$10,092	$8,893	$9,727	$22,326	$15,264	
Rate	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15	
# Turn ons	675	672	776	478	603	653	655	673	593	648	1,488	1,018	8,932
Meter Set	$4,575	$4,475	$3,193	$2,229	$2,450	$2,700	$2,729	$2,473	$2,120	$3,987	$5,161	$5,244	
Rate	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	
# Meter Sets	183	179	128	89	98	108	109	99	85	159	206	210	1,653
Returned Check	$1,160	$2,080	$2,180	$1,660	$1,160	$500	$1,160	$740	$740	$560	$780	$880	
Rate	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	
# Returned Checks	58	104	109	83	58	25	58	37	37	28	39	44	680
Reconnect Charge	$8,762	$13,843	$13,316	$11,774	$14,251	$10,797	$7,921	$6,978	$7,815	$11,845	$22,524	$6,883	
Rate	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	
# Reconnects	175	277	266	235	285	216	158	140	156	237	450	138	2,733
Seasonal Reconnect Charge	$550	$250	$109	-$9	$150	$50	$219	$145	$532	$2,513	$6,892	$1,311	
Rate	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	
# of Seasonal Reconnects	11	5	2	0	3	1	4	3	11	50	138	26	254

Question:

Please provide an electronic Excel spreadsheet via CD of the Company's exhibit, PGB-1, which includes all formulas.

Response:

Please see the electronic file named "CGC 2006 Rate Case Model Final with PGB-1.xls" for the electronic version of the Company's exhibit PGB-1. The worksheet labeled "Exhibit 1" contains the formulas which link to other worksheets within the workbook that was previously filed as work papers in Filing Guideline # 25.

Question:

Provide an update to your response to TRA FG 31 to include actual amounts for 8/06 –

9/06.

Response:

Please see the attached Schedule TRA DR 56, which contains updated customer counts by customer class for the months of 8/06 and 9/06. The meter reading schedule for 8/06 and 9/06 is the same as reported in TRA DR 27.

CHATTANOOGA GAS COMPANY
CGC Schedule TRA DR 56 NUMBER OF CUSTOMERS
Actuals from January 2000 through September 2006

	RESIDENTIAL	R-4 MULTI-FAMILY	COMMERCIAL	I1/T2	L1/T1	SS1	I1/T2 + T1	L1	T1	T3	SPECIAL CONTRACT
	Customers	Customers	Customers	Customers	Customers	Customers					Customers
Jan-00	49,182	5	8,033	25	47	1					1
Feb-00	49,447	5	8,110	25	47	1					1
Mar-00	49,026	5	8,000	27	47	1					1
Apr-00	49,333	5	8,160	27	47	1					1
May-00	49,917	5	8,085	27	47	2					1
Jun-00	48,259	5	7,829	27	47	2					1
Jul-00	45,452	5	7,469	27	47	4					1
Aug-00	45,552	5	7,281	27	47	3					1
Sep-00	47,876	5	7,695	27	47	1					1
Oct-00	48,274	5	7,727	27	47	2					0
Nov-00	49,295	5	7,859	29	44	3					0
Dec-00	49,988	5	8,076	29	45	1					0
Jan-01	50,522	4	8,205	27	43	2					1
Feb-01	50,650	4	8,291	27	44	1					1
Mar-01	50,682	4	8,271	28	43	3					1
Apr-01	50,445	4	8,231	27	44	3					1
May-01	49,503	3	8,055	28	43	3					1
Jun-01	48,759	4	7,894	28	43	3					1
Jul-01	48,448	4	7,794	27	44	3					1
Aug-01	47,982	5	7,731	28	45	3					1
Sep-01	47,869	4	7,714	28	43	0					1
Oct-01	48,167	4	7,726	27	44	0					1
Nov-01	49,342	4	7,844	28	43	3					1
Dec-01	49,918	4	8,007	28	42	1					1
Jan-02	51,159	4	8,327	27	43	2					1
Feb-02	51,332	4	8,389	27	43	3					1
Mar-02	51,447	4	8,391	26	44	3					1
Apr-02	51,117	4	8,300	27	43	3					1
May-02	50,526	4	8,141	28	41	3					1
Jun-02	50,005	4	8,035	28	41	3					1
Jul-02	49,701	4	7,945	28	42	3					1
Aug-02	49,349	4	7,889	28	42	3					1
Sep-02	49,275	4	7,885	30	42	3					1
Oct-02	49,600	4	7,916	28	44	3					1
Nov-02	50,724	4	8,096	28	41	3					1
Dec-02	51,523	4	8,337	26	42	3					1
Jan-03	51,902	4	8,409	26	42	3					1
Feb-03	52,128	3	8,465	26	42	3					1
Mar-03	52,129	3	8,464	26	41	4					1
Apr-03	51,494	3	8,352	26	42	4					1
May-03	50,657	3	8,199	26	41	5					1
Jun-03	50,237	3	8,068	27	41	5					1
Jul-03	49,882	3	7,958	30	39	8					1

CHATTANOOGA GAS COMPANY
CGC Schedule TRA DR 56 NUMBER OF CUSTOMERS
Actuals from January 2000 through September 2006

	RESIDENTIAL	R-4 MULTI-FAMILY	COMMERCIAL	I1/T2	L1/T1	SS1	I1/T2 + T1	L1	T1	T3	SPECIAL CONTRACT
Aug-03	49,703	3	7,942	29	40	1					1
Sep-03	49,746	3	7,912	28	41	3					1
Oct-03	50,514	3	7,988	29	40	3					1
Nov-03	51,431	3	8,174	29	40	2					1
Dec-03	52,100	3	8,369	29	40	2					1
Jan-04	52,513	3	8,476	27	39	7					1
Feb-04	52,761	3	8,532	28	40	4					1
Mar-04	52,728	3	8,518	28	40	4					1
Apr-04	52,367	3	8,456	29	39	5					1
May-04	52,289	3	8,372	29	39	4					1
Jun-04	51,483	3	8,218	29	40	5					1
Jul-04	50,893	3	8,075	30	39	3					1
Aug-04	50,639	3	7,992	29	40	6					1
Sep-04	50,861	3	7,996	30	40	6					1
Oct-04	51,059	3	8,052	30	40	6					1
Nov-04	51,929	2	8,186	30	39	6					1
Dec-04	52,859	2	8,412	30	39	6					1
Jan-05	53,318	2	8,462	23		6	15	1	25	0	1
Feb-05	53,578	2	8,584	23		6	15	1	25	0	1
Mar-05	53,809	2	8,580	23		5	15	1	25	0	1
Apr-05	53,684	2	8,601	23		5	15	1	25	0	1
May-05	52,640	2	8,430	23		4	15	1	26	0	1
Jun-05	52,172	2	8,189	23		5	15	1	25	2	1
Jul-05	51,674	2	8,142	23		5	15	1	25	2	1
Aug-05	51,586	2	8,163	23		5	15	1	25	2	1
Sep-05	51,694	2	8,125	23		5	15	1	25	2	1
Oct-05	51,695	2	8,149	23		5	15	1	25	2	1
Nov-05	52,472	2	8,269	23		5	15	1	25	2	1
Dec-05	53,383	2	8,531	23		5	15	1	25	2	1
Jan-06	53,654	2	8,595	23		5	15	1	24	2	1
Feb-06	53,769	2	8,604	23		5	15	1	23	2	1
Mar-06	53,738	2	8,574	24		5	14	1	23	2	1
Apr-06	53,374	2	8,444	24		5	14	1	23	2	1
May-06	52,825	2	8,316	24		5	14	1	23	2	1
Jun-06	52,214	2	8,198	24		5	14	1	23	3	1
Jul-06	51,776	2	8,120	24		5	14	1	23	3	1
Aug-06	51,776	2	8,080	24		5	14	1	22	3	1
Sep-06	51,655	2	8,073	24		5	14	1	22	3	1

Note: Industrial customer counts from January 2005 reflect the customers' rate class choice made in June 2005
Actuals through September 2006

Question:

Provide actual usage by customer class, by month, for 8/06 – 9/06.

Response:

Please see the attached Schedule TRA DR 57 for the actual usage by customer class, by month, for 8/06 and 9/06.

CHATTANOOGA GAS COMPANY
Usage by Customer Class by Month

	RESIDENTIAL	R-4 MULTI-FAMILY	COMMERCIAL	I1/T2	L1/T1	SS1	I1/T2 + T1	L1	T1	T3	SPECIAL CONTRACT
	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes					Volumes
Aug-06	64,926	369	137,971	150,323		176,810	118,317	5,746	211,549	6,611	50,404
Sep-06	66,996	312	135,611	144,995		171,582	119,963	4,718	194,007	6,774	66,087

Question:

Please list all states where the forecast model, including the changes made to the model since the last Chattanooga gas rate case and described in the pre-filed direct testimony of Philip Buchanan, has been submitted. Also, indicate whether such states adopted the model in their ratemaking decision. Please document the adoption of the model by providing Orders as appropriate.

Response:

The Company is aware that the basic forecast model as described in the testimony of Phil Buchanan has been used in both New Jersey and Florida. The Company has not performed research to determine all states where a similar model has been used. For New Jersey and Florida, the model is adapted to each jurisdiction based on tariff requirements and differing customer classes. The basic models are similar in that they incorporate the customer forecast methodology, multi-variate regression analysis performed in Forecast Pro, and the application of each jurisdiction's approved rate design. In New Jersey, the model has been used in multiple gas cost recovery filings by Elizabethtown Gas, as the gas cost rates are based on a forecast of customers and throughput. The most recent dockets filed by Elizabethtown Gas to adjust gas cost recoveries are GR00070470, GR00070471, GR03050423, GR05060494, and GR05060494. The final orders for these dockets are included as Exhibit TRA 58 A, B, C, D, and E in this response.

Elizabethtown Gas also used the model in their most recent base rate case, Docket Number GR02040245. The final order for this docket is included as Exhibit TRA 58 F.

Florida City Gas used the model in each of their two most recent base rate cases. The final order in the 2000 Docket Number 000768 and the final orders approving interim and permanent rates in the 2003 Docket Number 030569 are included as Exhibits TRA 58 G, H and I.

With the exception of the most recent Florida City Gas base rate case, the revenue forecast models are not expressly adopted in all of the attached final orders, but the models were used in each of the proceedings and the results of the models were adopted. Pages 6 through 9 of the final order of the most recent Florida City Gas, attached as Exhibit TRA 58 I, discuss the use of FCG's model, which is similar to the model used in this docket. The order states the following:

The number of therms was projected on a per customer basis using multiple regression techniques. Variations in therm usage per customer were modeled using economic, climatological, and time-trend variables. Having evaluated the assumptions, statistical properties, and output of these models, we find them to be appropriate.

All of the above mentioned exhibits are included on the attached CD due to the size of the exhibits.

Question:

On pages 12-13 of the pre-filed direct testimony of Philip Buchanan, Mr. Buchanan notes that the forecast model includes a cubic spline term in the residential and commercial consumption equations. Please provide the following information about the use of cubic splines in the context of forecasting natural gas consumption:

a. Provide all documentation from the Forecast Pro XE version 4 software discussing cubic splines.

b. Provide appropriate citations from academic and professional literature that utilize cubic spline terms to forecast natural gas consumption.

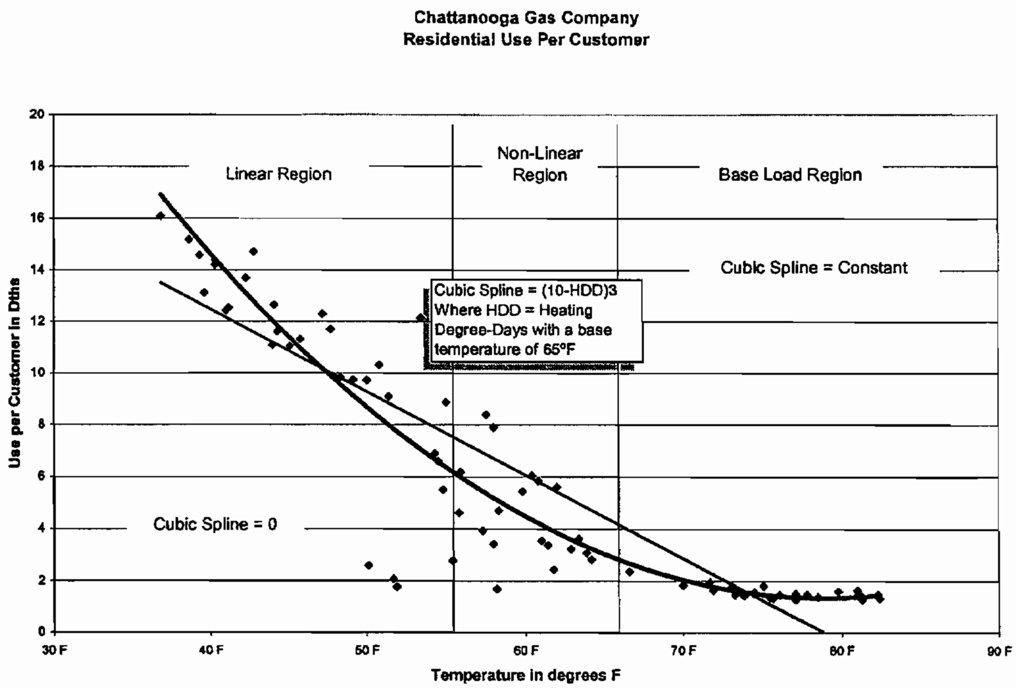
Response:

The cubic spline method is a standard regression technique that has been adapted to explain changing regions of temperature sensitivity that occur naturally in customer demand. Below is graph that depicts the three regions of customer demand based upon customer usage for residential customers of Chattanooga Gas Company. As can be seen on the graph, the region where temperatures are below 55°F appears to match a fairly linear pattern. However, for the region between 55°F and 65°f demand appears to vary in a non-linear manner with decreasing sensitivity to changes in temperature as temperature increases. The region above 65°F seems to exhibit what would traditionally be considered a base load consumption pattern. As can be seen on the graph, there are a large number of observations occurring in the 55°F to 65°F range. To more accurately forecast usage, the Company employs a regression variable modeling technique called cubic splining. What cubic splining does is introduce a discontinuous variable that has values as shown below.

For temperature < 55°F	Cubic Spline = 0
For temperature > 55°F	Cubic Spline = $(10\text{-HDD})^3$

Where HDD = Heating Degree Days with abase temperature of 65°F

This variable is then entered into a standard linear regression model as simply another variable to regress. This then allows entry into the model a term that has no effect on sensitivity to heating degree-days in the range below 55°F, that has an increasing non-linear reducing effect on temperature sensitivity in the region between 55°F and 65°F, and a maximum constant base load effect on temperatures above 65°F.



In response to Part a. of TRA DR 59, Forecast Pro XE does not contain discussions of the types of variables that can be used in regression analysis, thus no documentation from Forecast Pro XE is available. Forecast Pro XE is a software package that performs regression analysis and performs statistical tests on the results of the regression. The results of the regression statistics regarding the regressions performed by the Company in this case, including the statistical results of the inclusion of the cubic spline term are included as Exhibit PGB-4 in the pre-filed testimony of Phil Buchanan. For the residential use per customer regression, the cubic spline term has a 100% significance, which means that there is a 100% chance that the spline variable has a significant effect on usage. For the Commercial C-1 and proposed C-2 class use per customer regressions, the cubic spline variable has a 97% and 99% significance, respectively.

In response to Part b. of TRA DR 59, the use of splines in regression analysis is common. As an example, splines are discussed at length in <u>The Elements of Statistical Learning – Data Mining, Inference, and Prediction</u> by Trevor Hastie, Robert Tibshirani, and Jerome Friedman (Chapter 5 Basis Expansions and Regularization, section 5.2 – Piecewise Polynomials and Splines). Cubic splines are also discussed in <u>Econometrics, Theory and Applications</u> by Sukesh K. Ghosh (Chapter 6 The General Linear Model and Some

Problems, section 6.4.7 – Variation of Dummy Variable Representation: The Spline Functions). Both references discuss the use of spline functions where variables are discontinuous at join points, or knots. The use of splines in such a situation is similar to the Company's use of the spline variable when analyzing gas usage at different temperature ranges, with knots at 55^0 F and 65^0 F.

The use of the technique as applied to forecasting natural gas usage was presented by the Company's witness Dan Nikolich (NUI) at the Southern Gas Association (SGA) Gas Forecasters Forum, October 22-24, 2003. Similar practices were also discussed during the Forum by panelists Bill Gresham (NiSource), Ronald Brown (Marquette University), and Mark Quan (Itron, formerly of Regional Economic Research). The presentations of these panelists are attached as Exhibit TRA DR 59 A, Exhibit TRA DR 59 B, and Exhibit TRA DR 59 C respectively.

Gas Forecasters Forum

October 22-24, 2003
Hyatt Regency Tamaya Resort & Spa
Albuquerque, NM

Weather Normalization Strategies and Practices

SGA
LINKING PEOPLE, IDEAS, INFORMATION

Weather Normalization Strategies and Practices
Jim Fay, North Star Energy Group

NOTES

NORTH✦STAR ENERGY GROUP

Weather Normalization Strategies and Practices

Panel Discussion
3:00-4:15p

Bill Gresham, NiSource
Dan Nikolich, NUI

SGA LINKING PEOPLE. IDEAS. INFORMATION

NORTH✦STAR ENERGY GROUP

Issue 1 - Weather Data Used for Normalization

What is the best historical weather period to use for normalization: 30 year, 10 year, other?

- *What are the considerations and criteria?*
- *How do commissions and commission staffs view these?*
- *How do they affect forecasts?*

NORTH·STAR
ENERGY GROUP

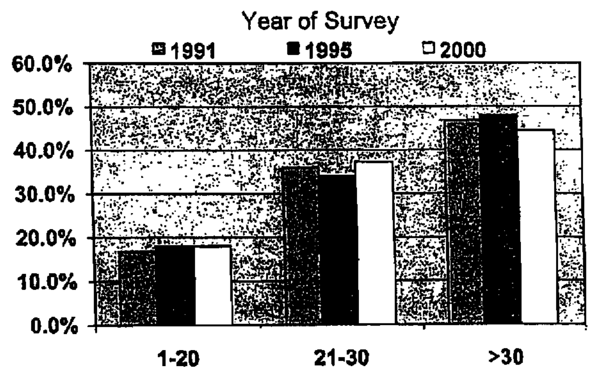
The 10-Year HDD Normal Is Less Than ("Warmer") than the 30-Year HDD Normal

	HDD 1970-2000	HDD 1990-2000	HDD 30 Yr – 10 Yr	Percentage 30 Yr – 10 Yr
Northeast	6042	5905	137	2.27%
Midwest	6535	6420	115	1.76%
South	3621	3543	77	2.13%
West	3789	3672	117	3.09%
U.S.	4793	4687	106	2.21%

Source: NOAA Data

NORTH·STAR
ENERGY GROUP

For Determining Design Day, Most Gas Utilities Use More than 30 Years of History



Number of Years of History Used: Design Day Average Temperature

Source: Forecasting and Supply Planning Practices: 2000 Survey Results, SGA

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ENERGY GROUP

Issue 2 - Weather Data Quality

What data review and adjustment is needed?

- *The ASOS data issue – a retrospective.*
- *What industry resources are available to help?*

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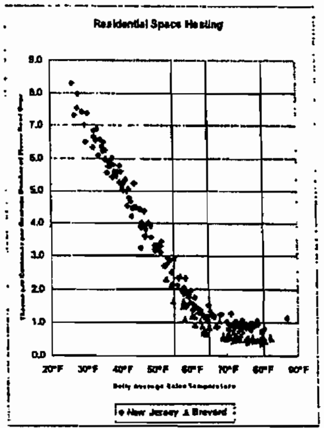
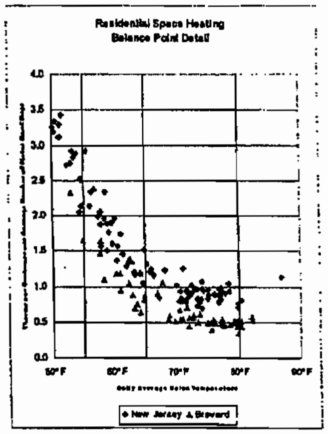
Issue 3 – Balance Point

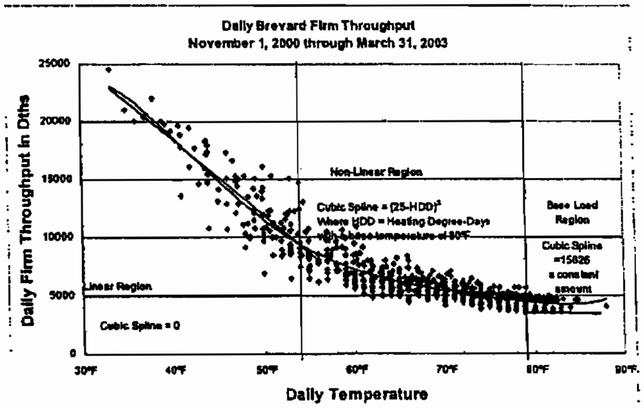
- How does the 65^0 base vary?
  - Does it vary seasonally?
  - Does it vary by sector (Residential vs. Commercial)?
  - Does it vary for new construction vs. existing?
  - How has it changed over time?
- How can a forecaster adjust the data (or the forecast) to deal with the fact that the 65^0 base is a very simplifying assumption?
- How can a forecaster improve accuracy by making the base adjustments?

Residential Heating Balance Points?

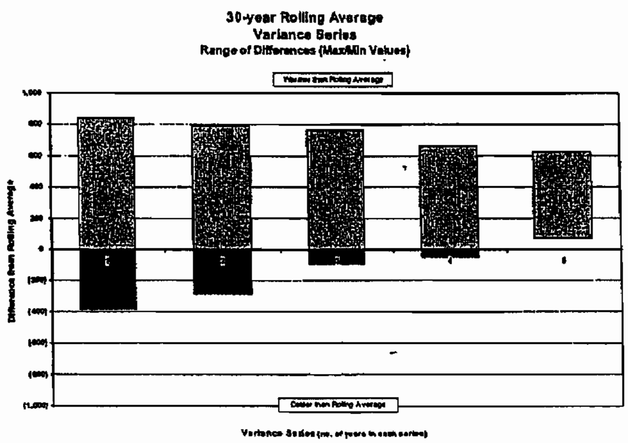




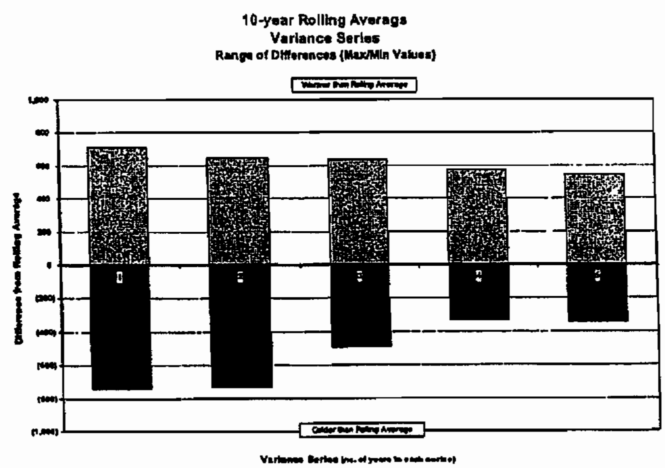
Balance Points and Cubic Splines



30 Year Normal 5 Year Rolling Variances



10 Year Normal 5 Year Rolling Variances



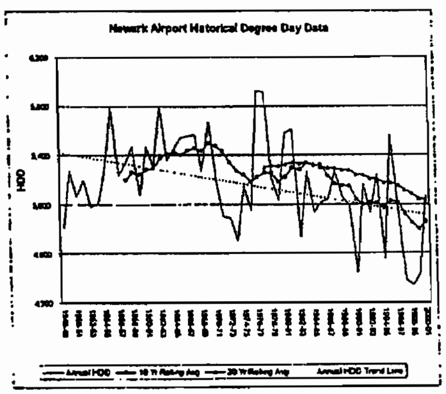
What is the best historical weather period to use for normalization: 30 year, 10 year, other?

- A Normal Weather Period is a forecast, and can be tested and evaluated like any other forecast.
- Performance of the weather normal depends upon a few key criteria and considerations?
  - Is there an underlying multi-year long term trend in the weather pattern?
  - What is the length of time the normal is expected to be used unchanged? 1 year, 5 years, 10 years?
  - What is the company's objective, better current cash recovery or lower rates?
  - What is the Regulator's objective lower base rates or are they willing to live with higher Weather Normalization Clause recoveries?

Daniel J. Nikolich
Manager Planning and Forecasting

Is there an underlying multi-year long term trend in the weather pattern ?

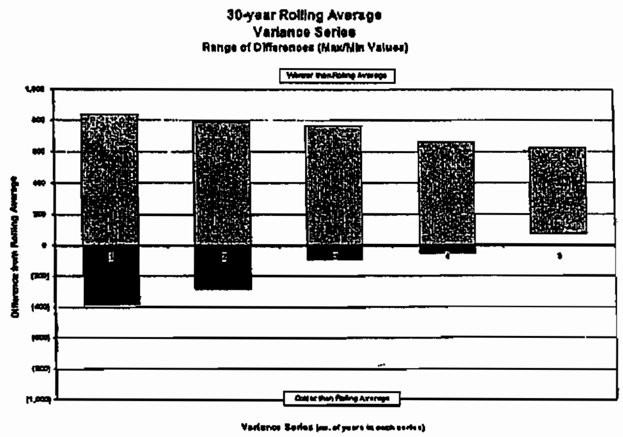
In NUI's NJ territory there was a long term warming trend!



- This implies that a straight average will under state weather in future periods. A bias exists!
- A 30 year average would and did lead to less than full recovery of the Company's revenue requirements through base rates.
- A 30 year average lead to almost continual recovery from rate payers through the Company's Weather Normalization Clause.

Daniel J. Nikolich
Manager Planning and Forecasting

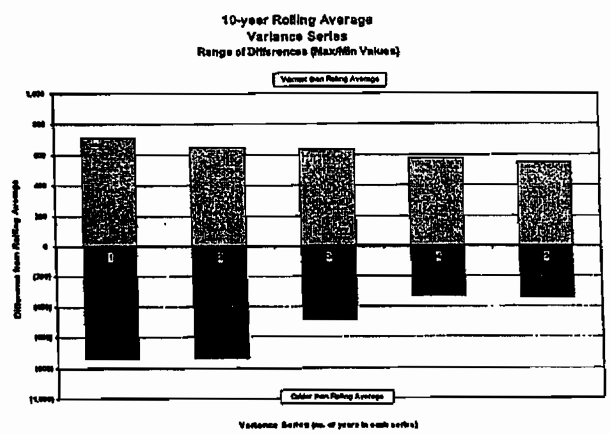
How to Measure the Bias? 30 Year Normal Example



Daniel J. Nikolich

Manager Planning and Forecasting

How to Measure Bias? 10 Year Normal Example



Daniel J. Nikolich

Manager Planning and Forecasting

Weather Data Quality – ASOS Revisited

What is ASOS?

ASOS is the NWS Automated Surface Observation System that was installed during the 1990's at all Federal weather observation sites.

Why does the installation of ASOS matter?

ASOS devices use an improved temperature sensing device that reports temperatures on average 0.84°F colder than the previous HO-83 device. This causes a discontinuity in data that is traditionally used to develop Normal weather patterns. What would 300 ghost heating degree days cost your company?

David J. Nikolich
Manager Planning and Forecasting

How can an Adjustment be made for ASOS? One approach

NUI employs an approach developed by Dr. David Robinson, the state climatologist for New Jersey called "Difference of Differences".

What is "Difference of Differences"?

- Observations from 4 weather stations where there was no change in instrumentation are employed to compare the average difference in temperature readings pre-installation of the ASOS device, and post installation.
- This average of these 4 comparisons of differences is what forms the "Difference of Differences" adjustments.
- The adjustments are then applied to historic pre ASOS weather data to place it on the same footing.

David J. Nikolich
Manager Planning and Forecasting

The Final Newark Airport "Difference of Differences"

Newark - Canoe Brook

	Difference HO83 ([illegible])	Difference ASOS ([illegible])	Difference of Differences HO83-ASOS
Oct	4.8	2.5	2.3
Nov	4.1	1.9	2.2
Dec	3.5	1.9	1.6
Jan	3.8	2.3	1.5
Feb	3.7	2.5	1.2
Mar	3.1	2.1	1.0
Apr	3.2	1.8	1.4
May	3.9	2.0	1.9
June	4.1	1.9	2.2
July	4.0	2.2	1.8
Aug	4.1	2.0	2.1
Sept	4.1	2.1	2.0

Newark - Little Falls

	Difference HO83 ([illegible])	Difference ASOS ([illegible])	Difference of Differences HO83-ASOS
Oct	4.4	3.0	1.4
Nov	3.4	2.3	1.1
Dec	3.0	2.6	0.4
Jan	3.4	3.0	0.4
Feb	3.2	2.9	0.3
Mar	3.0	2.9	0.1
Apr	3.0	2.3	0.7
May	3.2	1.9	1.3
June	2.8	2.1	0.7
July	3.1	2.2	0.9
Aug	3.4	2.2	1.2
Sept	3.8	2.5	1.3

Newark - New Brunswick

	Difference HO83 ([illegible])	Difference ASOS ([illegible])	Difference of Differences HO83-ASOS
Oct	3.8	2.2	1.6
Nov	3.0	1.8	1.2
Dec	2.5	1.4	1.1
Jan	2.8	1.6	1.2
Feb	2.7	1.8	0.9
Mar	2.7	2.0	0.7
Apr	3.3	1.9	1.4
May	3.9	2.2	1.7
June	4.1	2.4	1.7
July	3.8	2.3	1.5
Aug	4.0	2.2	1.8
Sept	3.5	1.8	1.7

Newark - Brooklyn

	Difference HO83 ([illegible])	Difference ASOS ([illegible])	Difference of Differences HO83-ASOS
Oct	0.1	(1.0)	1.1
Nov	(0.2)	(1.0)	0.8
Dec	(0.5)	(0.9)	0.4
Jan	(0.5)	(0.8)	0.3
Feb	(0.5)	(0.4)	(0.1)
Mar	0.6	0.3	0.3
Apr	1.5	0.1	1.4
May	1.5	0.5	1.0
June	2.2	0.3	1.9
July	1.6	0.4	1.2
Aug	1.1	(0.1)	1.2
Sept	0.6	(0.8)	1.4

Daniel J. Nikolich

Manager Planning and Forecasting

The Final Newark Airport "Difference of Differences" cont.

CALCULATION OF THE ASOS-RELATED TEMPERATURE MEASUREMENT ADJUSTMENT
(average for the 5 year period Oct 1995 through Sept 2001)
(In Degrees °F)

Newark (Oct 1996 - Sept 2001)

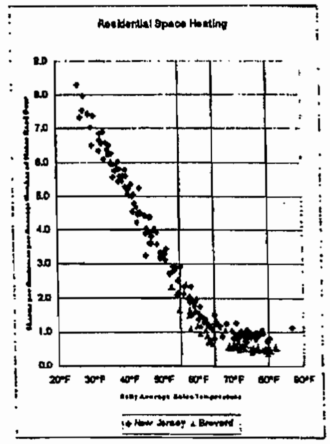
	Difference of Differences				
	Canoe Brook	New Brunswick	Little Falls	Brooklyn	4 Station Average
Oct	2.3	1.6	1.4	1.1	1.6
Nov	2.2	1.2	1.1	0.8	1.3
Dec	1.6	1.1	0.4	0.4	0.9
Jan	1.5	1.2	0.4	0.3	0.9
Feb	1.2	0.9	0.3	(0.1)	0.6
Mar	1.0	0.7	0.1	0.3	0.5
Apr	1.4	1.4	0.7	1.4	1.2
May	1.9	1.7	1.3	1.0	1.5
June	2.2	1.7	0.7	1.9	1.6
July	1.8	1.5	0.9	1.2	1.4
Aug	2.1	1.8	1.2	1.2	1.6
Sept	2.0	1.7	1.3	1.4	1.6
Avg	1.8	1.4	0.8	0.9	1.2

Daniel J. Nikolich

Manager Planning and Forecasting

Balance Points or Knots? Or do we really need the 65°F Base?

- Traditional analysis uses Heating degree days based upon a 65°F temperature.
- An assumed linear balance point where heating consumption begins is assumed.
- The validity of this assumption relies the majority of observations coming from temperatures below 55°F.
- Also on the assumption that Heating sensitivity does not change gradually over a range of temperatures.



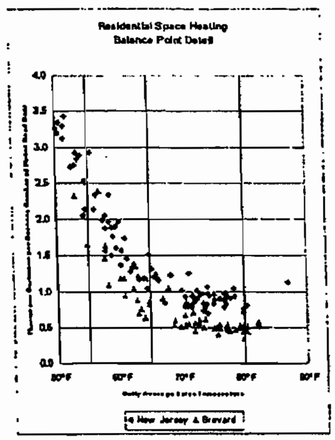
Daniel J. Mikotich
Manager Planning and Forecasting

Does Heating sensitivity change gradually over a range of temperatures?

The graph at the right presents a scatter plot of average residential heating customer consumption to temperature.

Note:

- That first, demand does not appear to change in linear fashion below 55°F.
- Next, that demand in both Florida and New Jersey appear to gradually change from 55°F to 80°F.



Daniel J. Mikotich
Manager Planning and Forecasting

How Can This Gradual Sensitivity Change be Modeled?

Add cubic spline terms to the model's regression

What are "Cubic Spline" terms?

- Discontinuous variables that introduce non-linear effects to a linear multi-variate model.

How are Cubic spline terms employed?

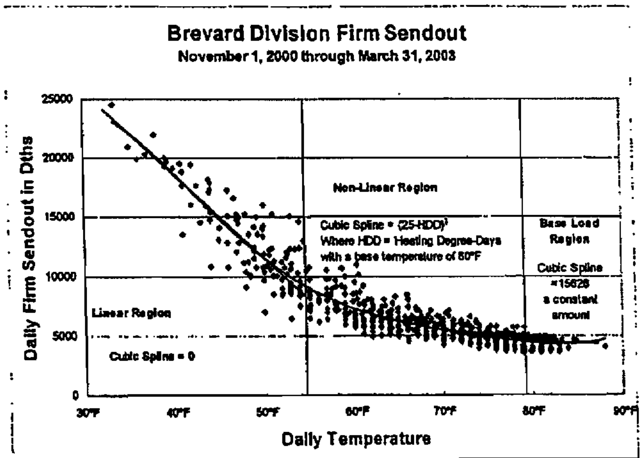
- Break points or "knots" are determined first.
- All values of heating degree days greater than the knot set to zero.
- A separate functional form based upon the following equation is developed for heating degree day values less than knot.

  Cubic Spline =(Knot –HDD)^3

- The terms are then entered in to the linear regression simply as another variable.

Daniel J. Nikolich
Manager Planning and Forecasting

Cubic Splines



Daniel J. Nikolich
Manager Planning and Forecasting

NiSource

NiSource Energy
Distribution Group

Weather Normalization and Balance Point Temperature

Presented to Southern Gas Association Gas Forecaster's Forum
William Gresham
Manager of Forecasting and Financial Systems
NiSource Energy Distribution
October 2003

NiSource

NiSource Energy
Distribution Group

NiSource

Natural Gas Pipelines and Distribution

Electric Generation, Transmission and Distribution

Energy Services

Eleven Natural Gas Distribution Companies

• IN OH PA KY MD VA MA ME NH

One Electric Company

IN

NiSource
NiSource Energy Distribution Group

Nisource Distribution
Weather Normalization Procedure

Classic Approach:

- Normalize monthly volume per customer
- Base Load is average volume per customer per day in July and August times days in the month
- Heat Load is Total Volume/Customer less Base Load/Customer
- Normal Volume/Customer =
  Base Load + Heat Load * (Normal HDD/Actual HDD)

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NiSource Energy Distribution Group

Nisource Distribution
Weather Normalization Procedure

New Age Touch:

- Normal HDD = 30 years ended 2001
- Normal values calculated daily – no interpolation
- Daily progression of normal values may not be smooth

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NiSource Energy Distribution Group

Nisource Distribution

Weather Normalization Procedure

Avant-Garde Twist :

- Balance Point Temperature varies by company and by class
  - Range = 60 to 63 degrees with one outlier at 67 degrees
  - 65 degrees not verified in any market

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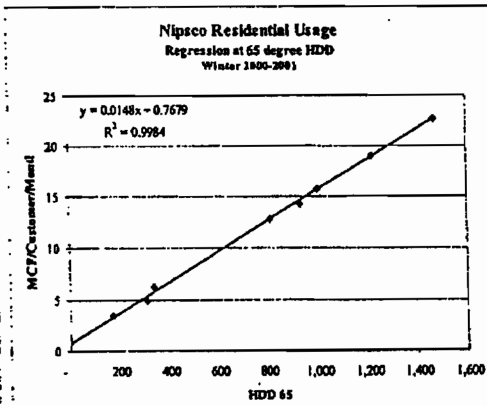
Nisource Distribution

Balance Point Temperature



Regression Approach

- One Season to hold other factors constant
- Strong Linear Relationship
- Implied Base Load at 65 is too low

  (0.8 < 2.3)

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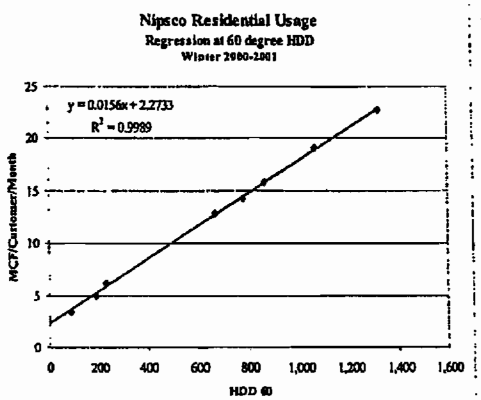
NiSource Energy Distribution Group

Nisource Distribution
Balance Point Temperature



Regression Approach

at the true balance point temperature

Implied Base Load = Observed Base Load

(2.3 = 2.3)

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Nisource Distribution
Balance Point Temperature

Applications for Calculated BPT v 65

- More Accurate representation of historical data and trend
- More Accurate delivery schedules in the shoulder months
- More Accurate bill estimations

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NiSource Energy Distribution Group

Nisource Distribution
Balance Point Temperature

Advantage of Calculated BPT with Classic Approach

- Ease of calculation and explanation
- Variable heat load response by month
- Regressions run at most once per year

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NiSource Energy Distribution Group

Nisource Distribution
Balance Point Temperature

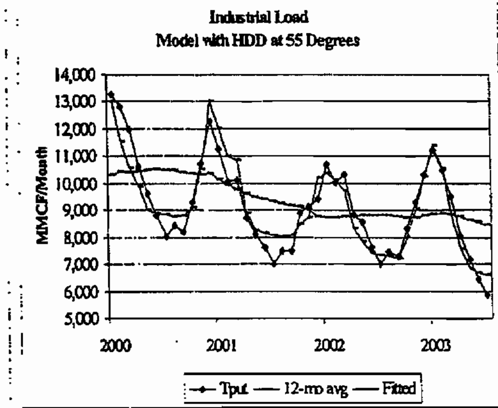
Balance Point Temperatures

	Res	Com		Res	Com
• KY	63	64	IN	60	60
• MD	63	63	MA	60	60
• OH	62	61	NH	60	60
• PA	62	62	ME	60	60
• VA	62	67			

NiSource
NiSource Energy Distribution Group

Nisource Distribution

Industrial Balance Point Temperature



BPT = 55

Suggested by Industrial Sales

Regression

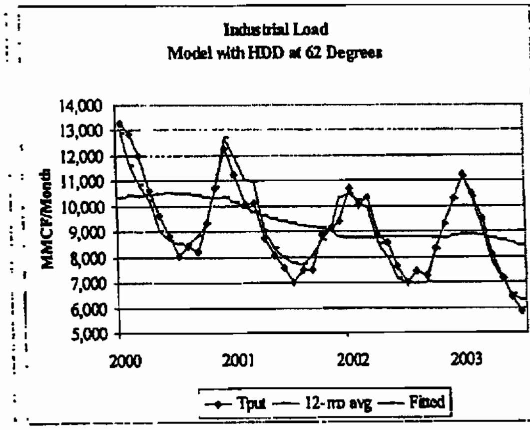
with Trend and HDD

Good Fit

NiSource
NiSource Energy Distribution Group

Nisource Distribution

Industrial Balance Point Temperature



BPT = 62

Regression

with Trend and HDD

Better Fit

Peaks and Valleys

OK, Who is Playing with the Thermostat?

Ronald H. Brown
Marquette University
ronald.brown@marquette.edu
www.gasday.com

Gas Forecasters Forum
Albuquerque, NM
23-Oct-2003

Marquette University

- We have been researching gas demand forecasting models since 1993.
- Our demand forecasting models are used around the country to forecast 18% of the nation's daily gas usage.
- 70+ students have been involved in this work.

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At last year's Gas Forecasters Forum, David Hughes (Nicor) and I talked about Load Growth over Time

- What growth trends are we seeing over various customer bases?
- Is the HDD reference temperature changing?
- How can we better forecast load demand in the shoulder months?

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2-Parameter Model

$$\hat{y}_k = \beta_0 + \beta_1 HDD_k$$

- The sendout for the *k*-th day is estimated as base load plus heat factor times HDD for the *k*-th day.
- Separate models are fit to each year of data.

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Using Only 2002-2003 Data

$$\hat{y}_k = \beta_0^{03} + \beta_1^{03} HDD_k$$

Using Only 2001-2002 Data

$$\hat{y}_k = \beta_0^{02} + \beta_1^{02} HDD_k$$

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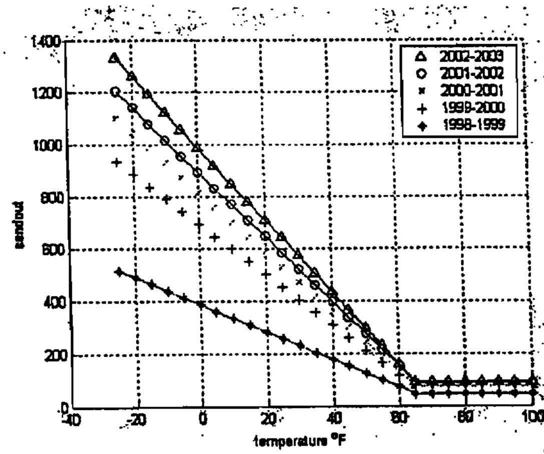
Estimated Sendout vs. Temperature for Each of the Five Years



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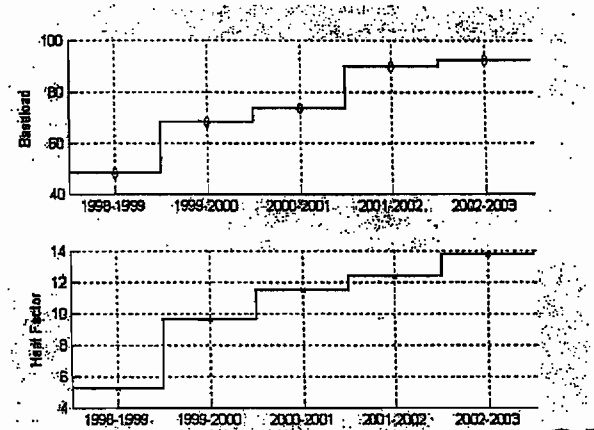
Base Load and Heat Load Factors for Each of the Five Years



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Adjusting Data From Two Years Ago to Act Like it Occurred Last Year

For the 2001-2002 heating season data:

$$\overset{new}{y}_k = y_k + (\beta_0^{03} - \beta_0^{02}) + (\beta_1^{03} - \beta_1^{02})HDD_k$$

Now the "new" 2001-2002 sendout data has the same base load and heat load factor as the 2002-2003 data

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Adjusting Data From Three Years Ago to Act Like it Occurred Last Year

For the 2000-2001 heating season data:

$$\overset{new}{y}_k = y_k + (\beta_0^{03} - \beta_0^{01}) + (\beta_1^{03} - \beta_1^{01})HDD_k$$

Now the "new" 2000-2001 sendout data has the same base load and heat load factor as the 2002-2003 data

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Higher Order Models

- Better model fit (reduced residual errors)
- Can model and observe additional gas consumption characteristics

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3-Parameter Model

$$\hat{y}_k = \beta_0 + \beta_1 HDD_k^{65} + \beta_2 HDD_k^{55}$$

- Automatically optimizes heating degree day reference temperatures

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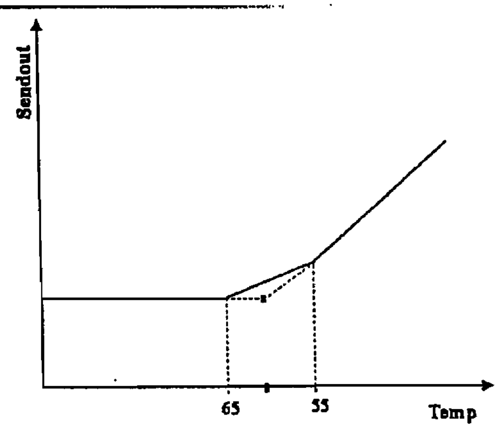
Optimal HDD Reference Temperature Calculation



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5-Parameter Model

$$\hat{y}_k = \beta_0 + \beta_1 HDD_k^{65} + \beta_2 HDD_k^{55} + \beta_3 \Delta HDD_k + \beta_4 CDD_k^{65}$$

- HDD_{lag} term: $\Delta HDD_k = HDD_k - HDD_{k-1}$
- CDD term

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Fit models on one year of data, but window it month by month, i.e.,

- Jan 95 – Dec 95
- Feb 95 – Jan 96
- Mar 95 – Feb 96

and so on

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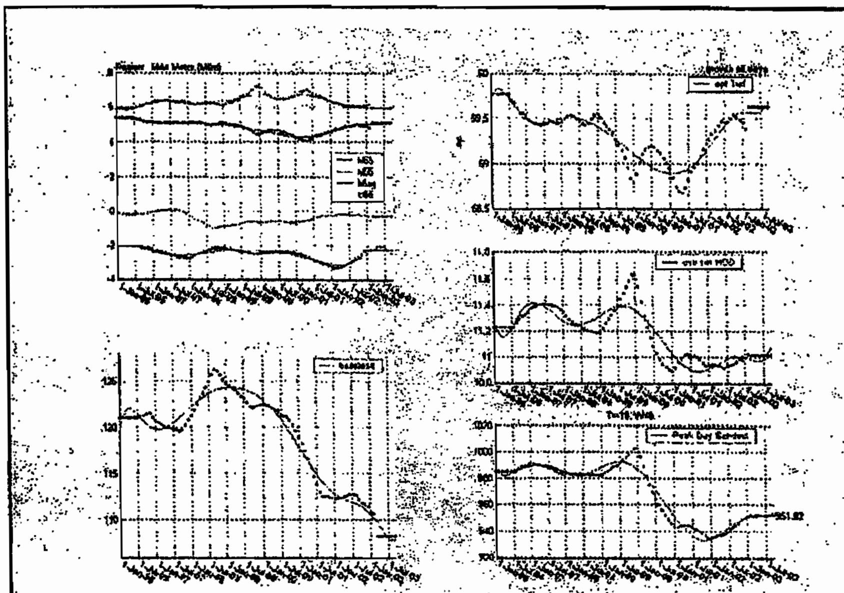

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Observations

- 2000-2001: base load, heat load factor, and reference temperature all decrease
- 2001-2002: base load and heat load factor continues to decrease, but reference temperature rebounds
- But this is just one customer base. Are other customer bases acting similarly?

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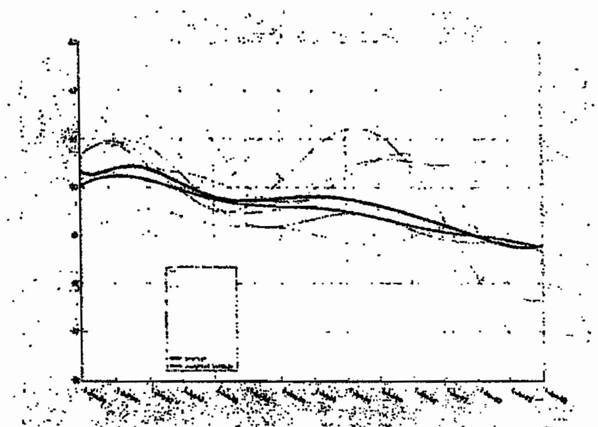
Optimal HDD Reference Temperature for 11 Areas in Wisconsin



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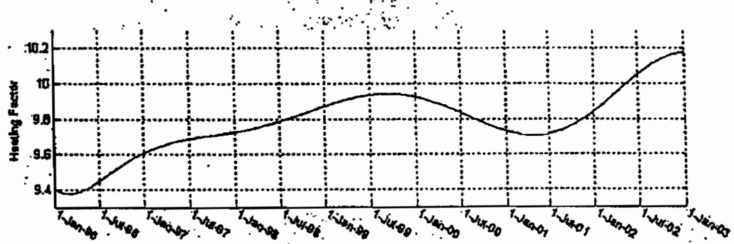
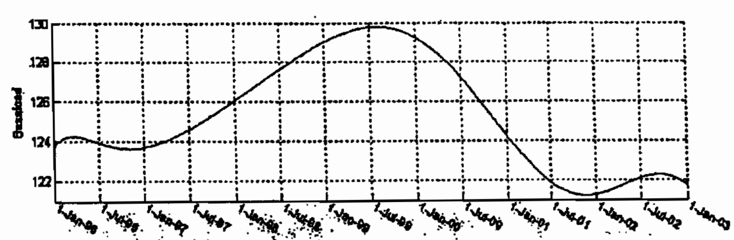
Heating Factor and Baseload for the 11 areas in Wisconsin





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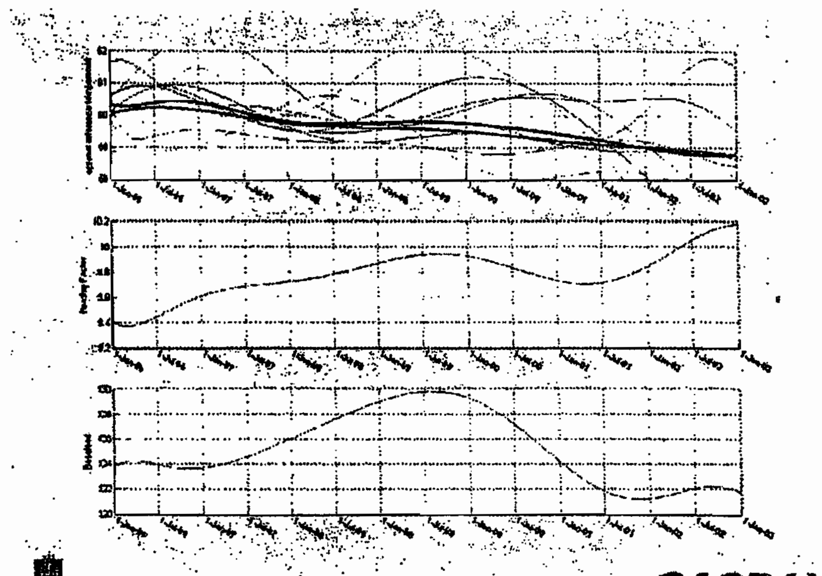

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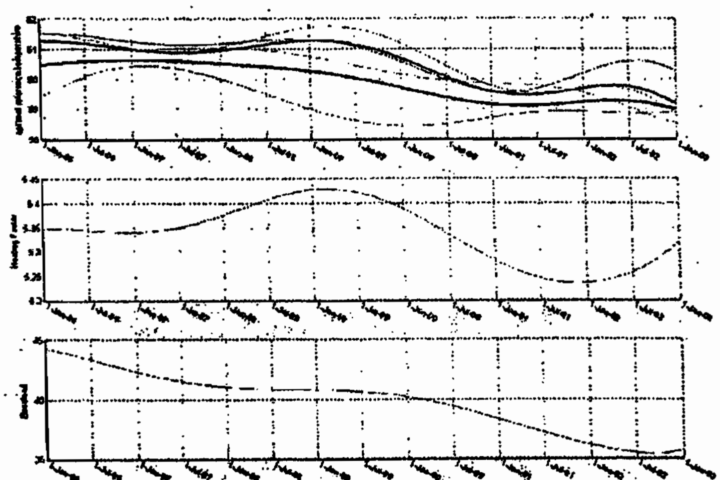
Other Midwest Areas



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Characteristics Over Time

- Optimal HDD reference temperature has dropped 1° to 1.5° since 1996.
- Heating load factors dipped in 2000-2001 and are starting to come back up.
- Baseload dipped in 2000-2001 and is not recovering.
- There is variance from area to area.

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Forecasting Demand in the Shoulder Months

What are they doing with their thermostats?

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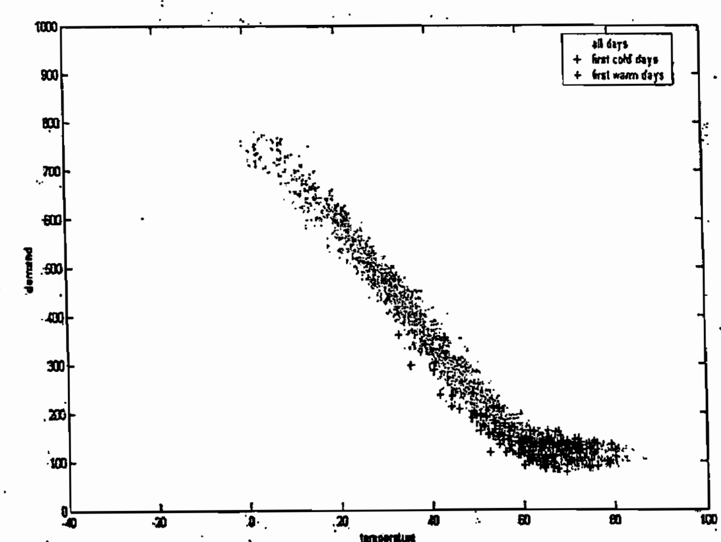
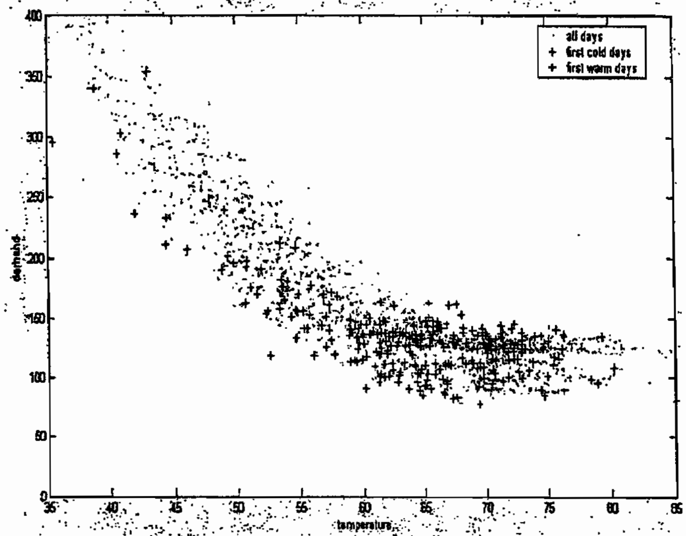
First Cold Days

- Some customers do not turn their furnaces on until they are cold.
- Some customers try not to turn on their furnaces until a certain day.
- Even after customers turn on their furnaces, they turn them off if there is a warm day.
- We can better forecast demand on these days if we can quantify these characteristics.





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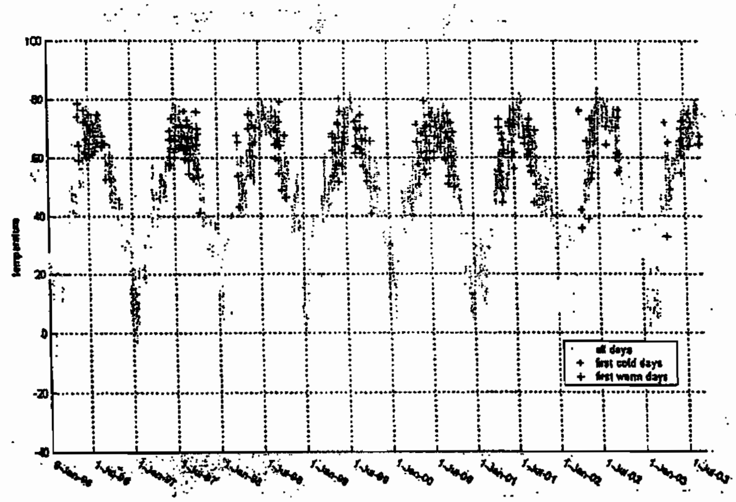

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First Cold Days Characteristics

- The colder it is, the more furnaces get turned on.
- Once the furnaces are on, they stay on until a warm day.

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Let F_k be a measure of the furnaces on.

Consider the expression:

$$F_k = HDD_k + 0.7 * F_{k-1}$$

Suppose F_{k-1} has a value of 30 (~ 50% Furnaces are on) and suppose the average temperature on the *k-th* day is 50°.

$$F_k = 15 + 0.7 * 30 = 36$$

(~ 60% Furnaces are on)

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measure of furnaces on

- To model furnaces turning off faster, allow the HDD_k term to go negative. (This also helps model the first warm days in the spring.)
- Scale the function to be between 0 and 1.

$$F_k = \min\left[\max\left(\frac{65 - T_k + 0.7 * F_{k-1}}{60}, 0\right), 1\right]$$

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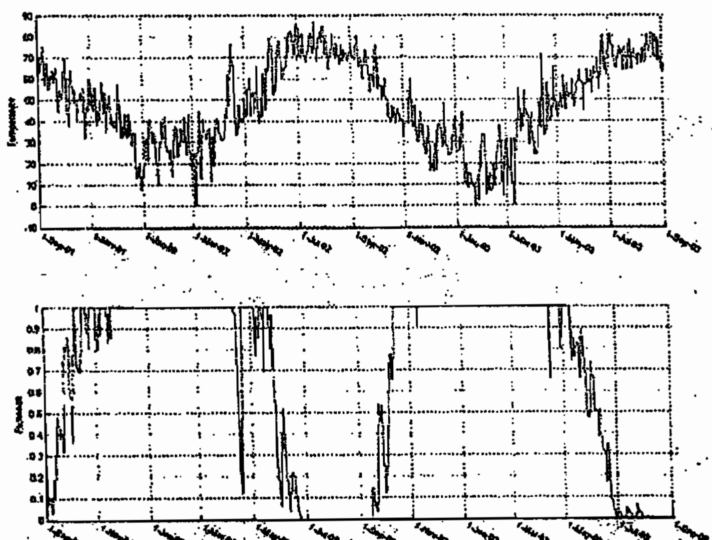

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Using *Furnaces On* in a model to forecast gas demand

Either

- Use F_k as another input into an LR or ANN model, or
- Multiply the HDD_k term by

$$(1-\alpha)+\alpha F_k$$

Where α is about 0.25

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Summary

- Gas demand characteristics are changing over time.
- More accurate demand forecast models can be built by "growing" historical data.
- Modeling behavior such as when furnaces are turned on and off improve demand forecasting models.

MARQUETTE UNIVERSITY GASDAY

Contact Information

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Gas Forecasters Forum

October 22-24, 2003
Hyatt Regency Tamaya Resort & Spa
Albuquerque, NM

"Techniques to Improve Your Forecast"

SGA
LINKING PEOPLE. IDEAS. INFORMATION

"Techniques to Improve Your Forecast"
Mark Quan, Itron

NOTES

Electric / Gas / Water

Techniques to Improve Your Forecast – II

Mark Quan
Itron

Itron
Knowledge to Shape Your Future

About Itron Forecasting

- **Itron is a leader in meter data collection and energy information management**
- **October 2002, Itron acquired Regional Economic Research (RER), a leader in short-term forecasting**
- **Itron/RER has over 20 years of experience developing and supporting software for the utility industry**
- **Offices in San Diego, Boston, and Vancouver (WA)**
- **Over 100 systems up and running:**
  - Automated System Load Forecasting
  - Retail Forecasting
  - Profiling
  - Price Forecasting
  - Budget Forecasting

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Agenda

Examine building a daily throughput forecast model

Topics

1. Regression Basics
2. Load Weather Relationship
3. Wind Impacts
4. Yesterday's Temperature Impacts

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Agenda

Examine building a daily throughput forecast model

Topics

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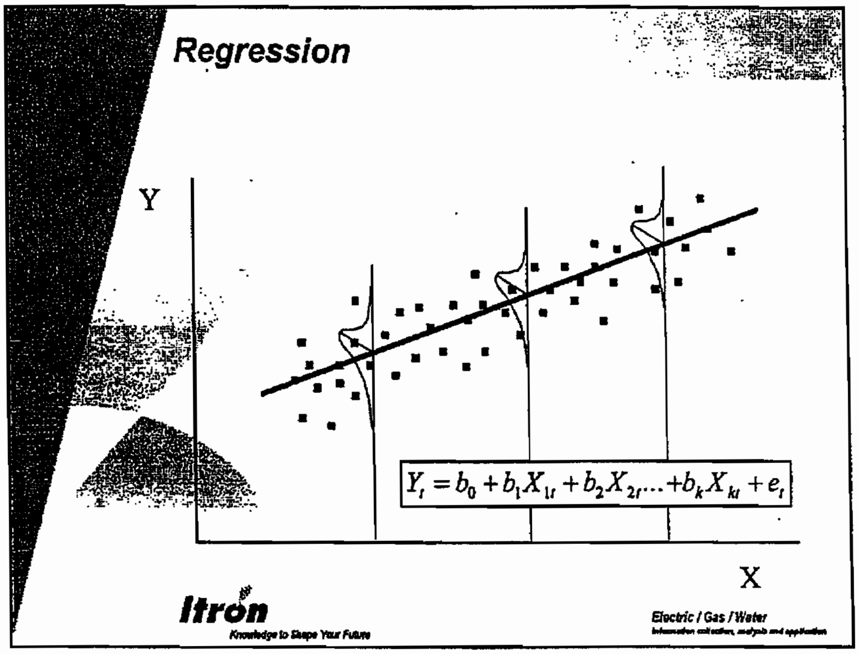
Regression
Y
$Y_t = b_0 + b_1X_{1t} + b_2X_{2t} ... + b_kX_{kt} + e_t$
X
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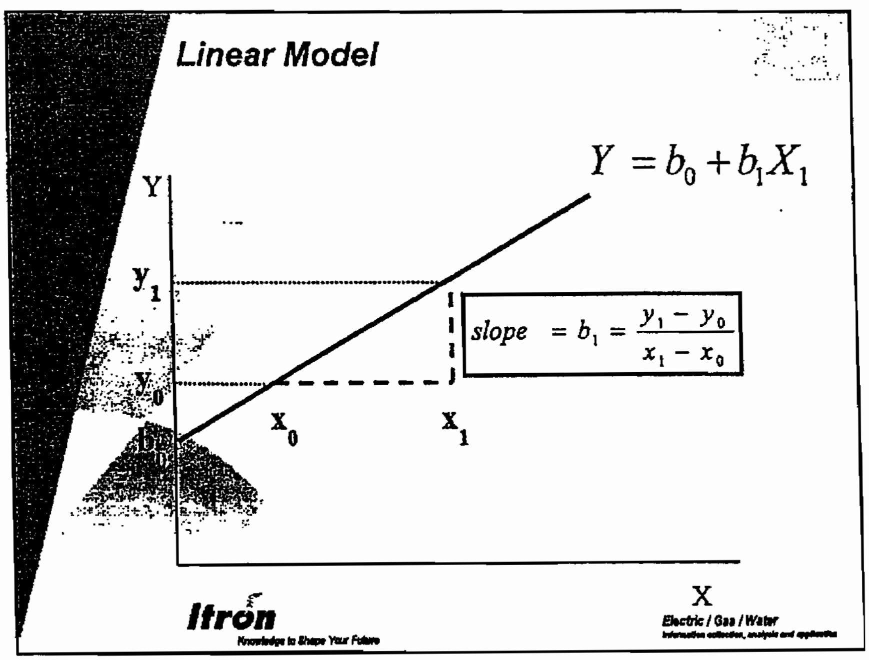
Linear Model
$Y = b_0 + b_1X_1$
Y
y_1
$slope = b_1 = \frac{y_1 - y_0}{x_1 - x_0}$
y_0
x_0
x_1
b_0
X
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Agenda

Examine building a daily throughput forecast model

Topics

1. Regression Basics
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4. Yesterday's Temperature Impacts

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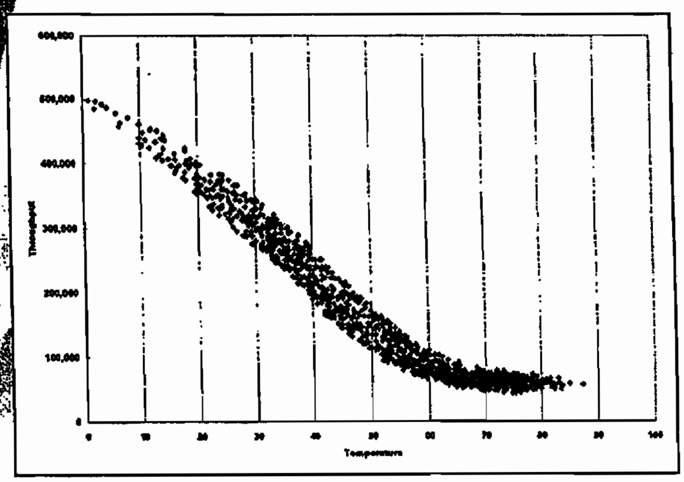
Electric / Gas / Water
Information collection, analysis and application

Throughput/Temperature Relationship



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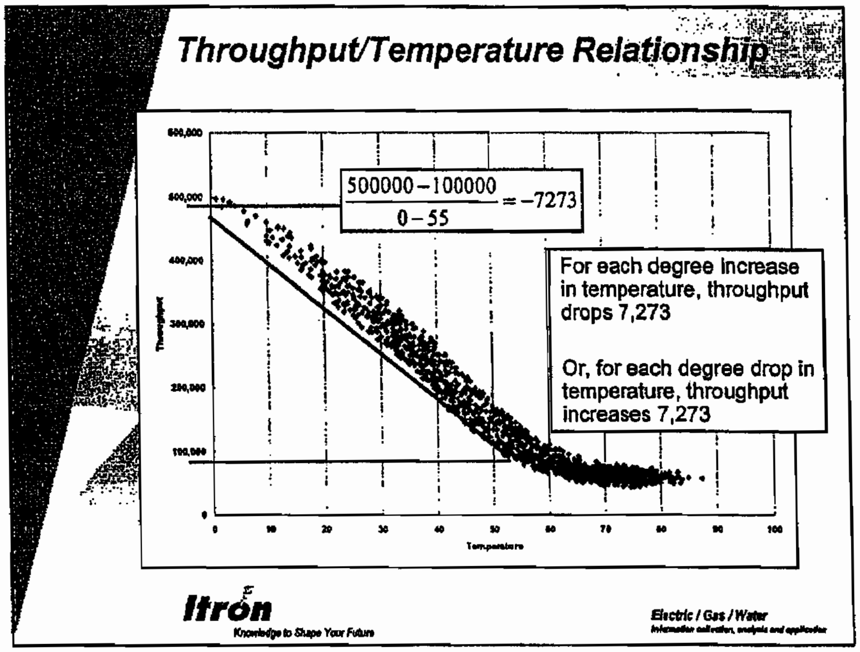
Information collection, analysis and application


Throughput/Temperature Relationship
(500000 − 100000) / (0 − 55) = −7273
For each degree increase in temperature, throughput drops 7,273
Or, for each degree drop in temperature, throughput increases 7,273
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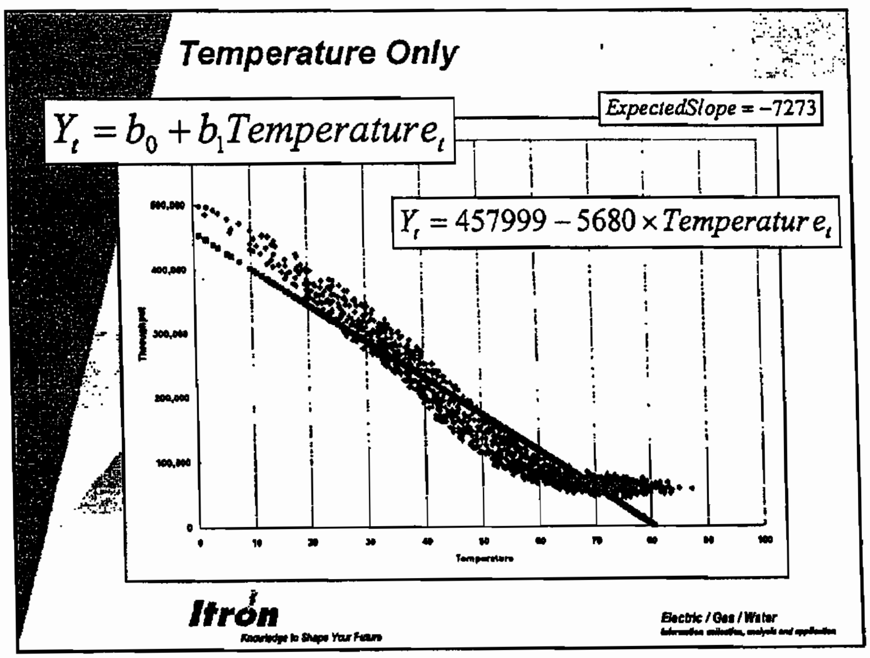
Electric / Gas / Water


Temperature Only
Y_t = b_0 + b_1 Temperature_t
ExpectedSlope = −7273
Y_t = 457999 − 5680 × Temperature_t
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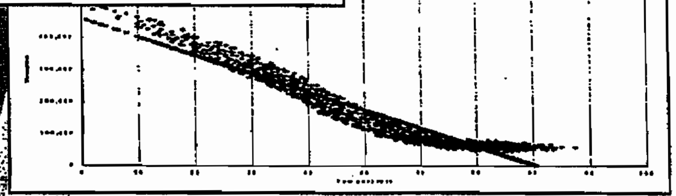
Electric / Gas / Water

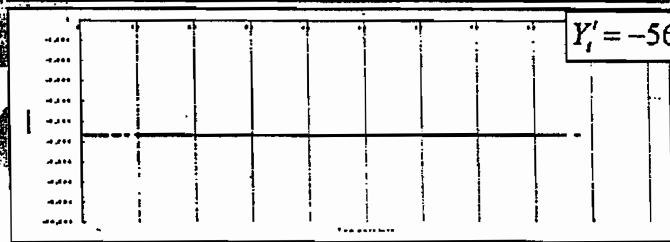
Temperature Only Derivative

$$Y_t = b_0 + b_1 Temperature_t$$

$ExpectedSlope = -7273$



$Y_t' = -5680$



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Temperature Bin Approach

Create a Set of Binary Variables

- Bin1 = (AvgDB <= 10)
- Bin2 = (10 < AvgDB) * (AvgDB <= 20)
- Bin3 = (20 < AvgDB) * (AvgDB <= 30)
- Bin4 = (30 < AvgDB) * (AvgDB <= 40)
- Bin5 = (40 < AvgDB) * (AvgDB <= 50)
- Bin6 = (50 < AvgDB) * (AvgDB <= 60)
- Bin7 = (60 < AvgDB) * (AvgDB <= 70)

Regress Load on the set of Binary Variables

$$Y_t = b_0 + b_1 Bin_{1,t} + b_2 Bin_{2,t} + \ldots + b_7 Bin_{7,t}$$

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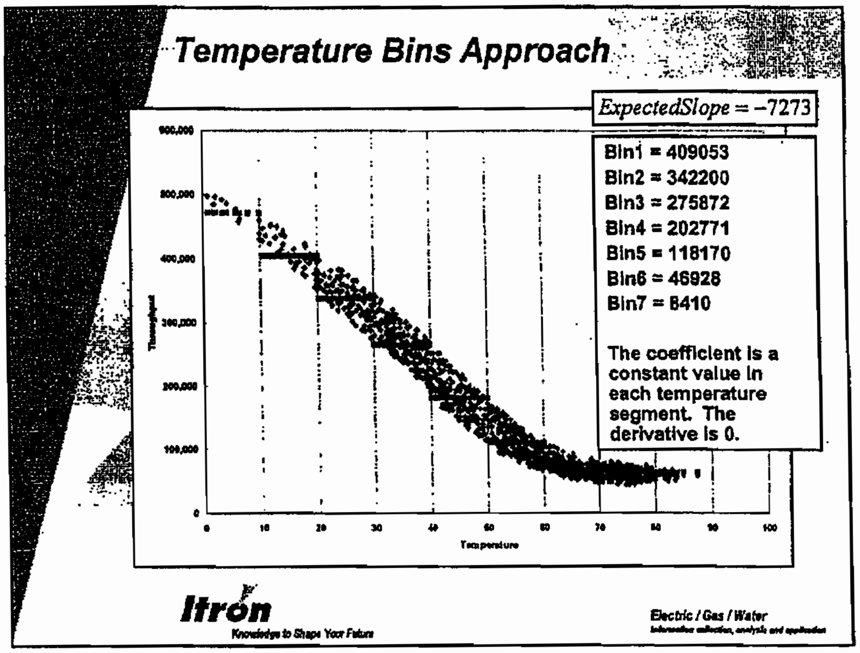
Temperature Bins Approach
ExpectedSlope = −7273
Bin1 = 409053
Bin2 = 342200
Bin3 = 275872
Bin4 = 202771
Bin5 = 118170
Bin6 = 46928
Bin7 = 8410
The coefficient is a constant value in each temperature segment. The derivative is 0.
Temperature
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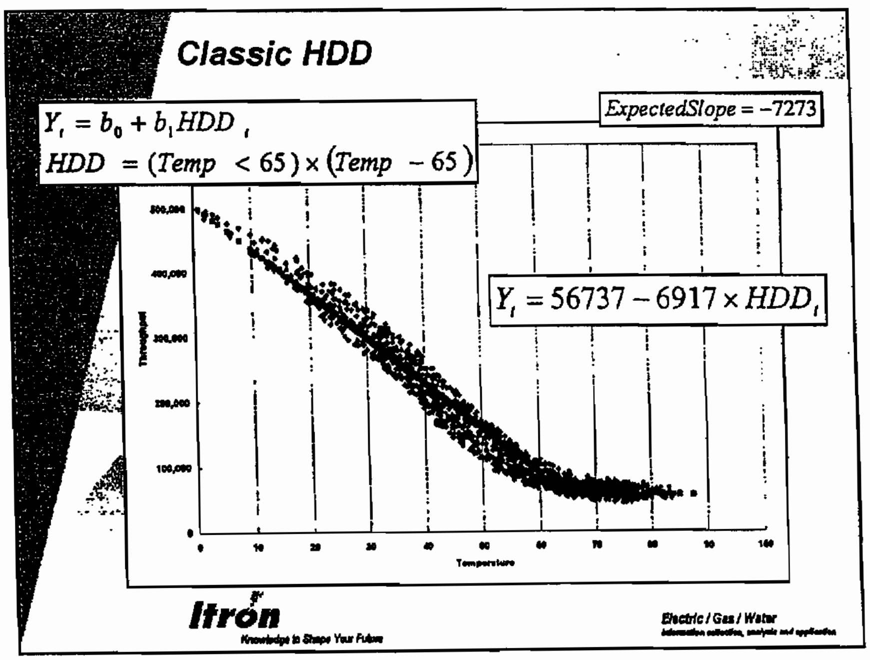
Classic HDD
ExpectedSlope = −7273
$Y_t = b_0 + b_1 HDD_t$
$HDD = (Temp < 65) \times (Temp - 65)$
$Y_t = 56737 - 6917 \times HDD_t$
Temperature
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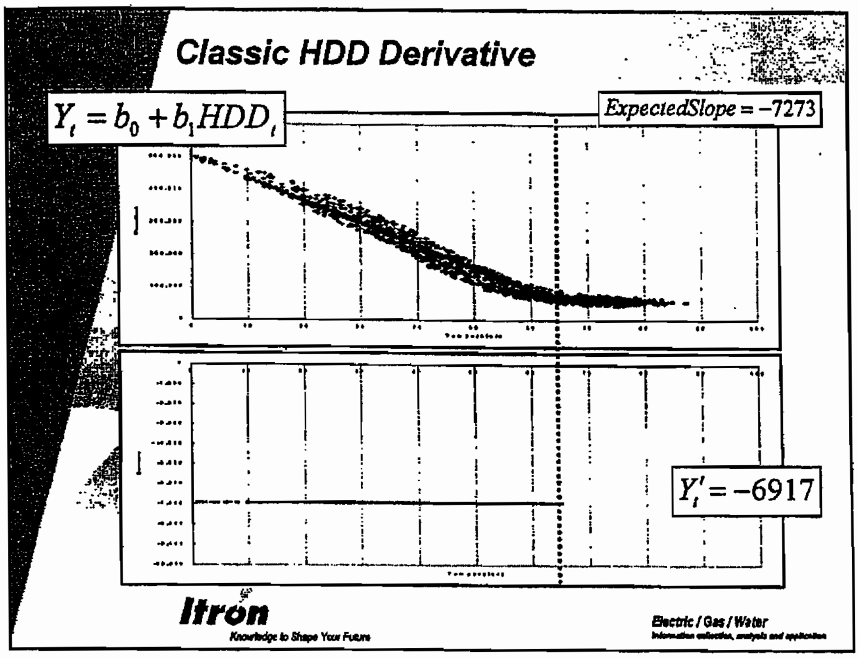
Classic HDD Derivative
$Y_t = b_0 + b_1 HDD_t$
$ExpectedSlope = -7273$
$Y_t' = -6917$
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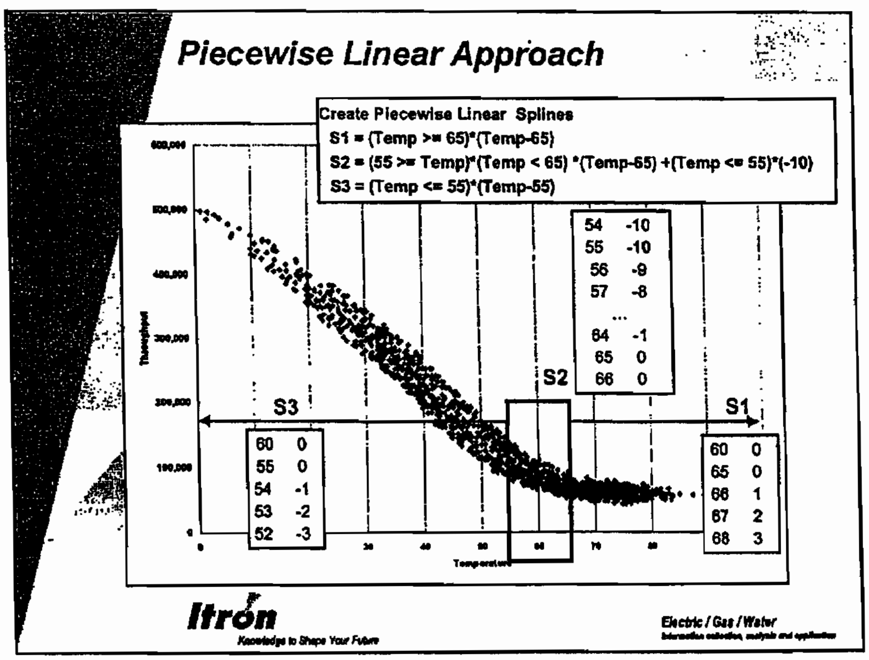
Piecewise Linear Approach
Create Piecewise Linear Splines
S1 = (Temp >= 65)*(Temp-65)
S2 = (55 >= Temp)*(Temp < 65) *(Temp-65) +(Temp <= 55)*(-10)
S3 = (Temp <= 55)*(Temp-55)
54 -10
55 -10
56 -9
57 -8
...
64 -1
65 0
66 0
S2
S3
60 0
55 0
54 -1
53 -2
52 -3
S1
60 0
65 0
66 1
67 2
68 3
600,000
500,000
400,000
300,000
200,000
100,000
0
Temperature
Itron
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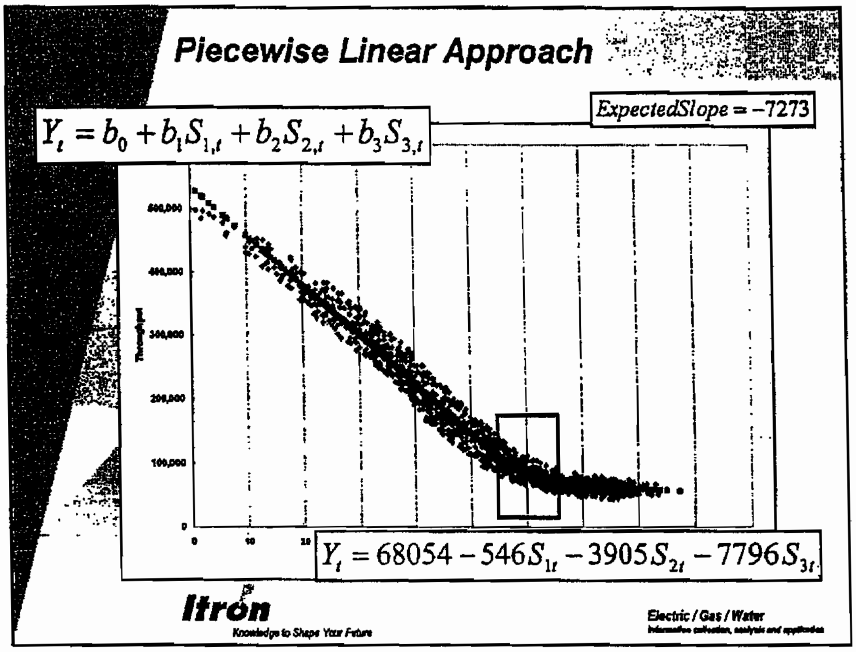
Piecewise Linear Approach
$ExpectedSlope = -7273$
$Y_t = b_0 + b_1 S_{1,t} + b_2 S_{2,t} + b_3 S_{3,t}$
$Y_t = 68054 - 546 S_{1t} - 3905 S_{2t} - 7796 S_{3t}$
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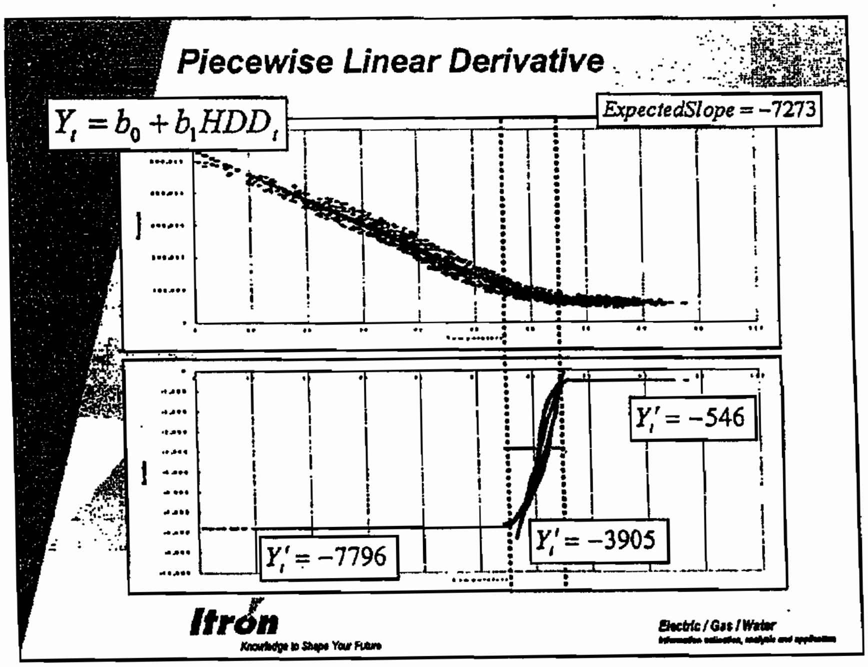
Piecewise Linear Derivative
$ExpectedSlope = -7273$
$Y_t = b_0 + b_1 HDD_t$
$Y_t' = -546$
$Y_t' = -3905$
$Y_t' = -7796$
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Linear Regression is Linear in the Parameters

You can make all kinds of transformations of the X variables – but must be linear in the parameters

$$\hat{Y}_t = \hat{b}_0 + \hat{b}_1 X_{1t} + \hat{b}_2 X_{1t}^{\,2} \ldots + \hat{b}_k X_{kt}$$

$$\ln \hat{Y}_t = \hat{b}_0 + \hat{b}_1 \ln X_{1t} + \hat{b}_2 \ln X_{1t}^{\,2} \ldots + \hat{b}_k \ln X_{kt}^{\,3}$$

$$\hat{Y}_t = \hat{b}_0 + \hat{b}_1 X_{1t} X_{2t} + \hat{b}_2 X_{2t}$$

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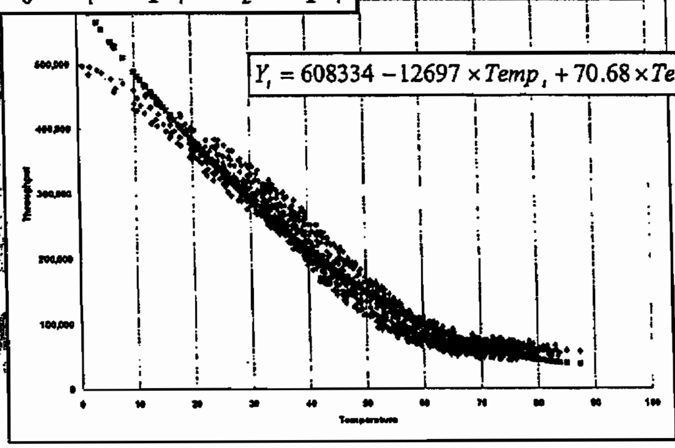
Quadratic Equation

$$Y_t = b_0 + b_1 Temp_t + b_2 Temp_t^{\,2}$$

$$ExpectedSlope = -7273$$

$$Y_t = 608334 - 12697 \times Temp_t + 70.68 \times Temp_t^{\,2}$$



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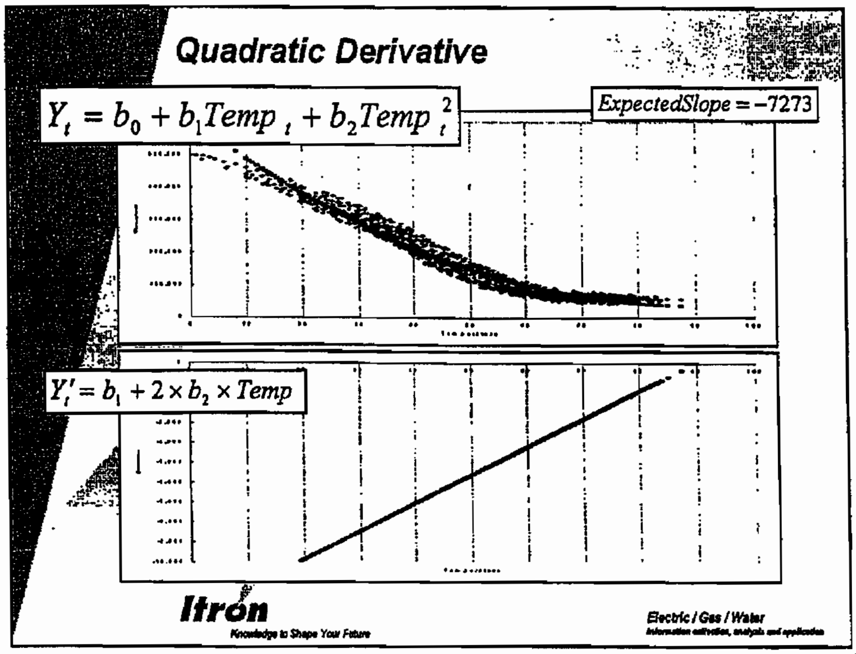

Quadratic Derivative
$Y_t = b_0 + b_1 Temp_t + b_2 Temp_t^2$
$ExpectedSlope = -7273$
$Y_t' = b_1 + 2 \times b_2 \times Temp$
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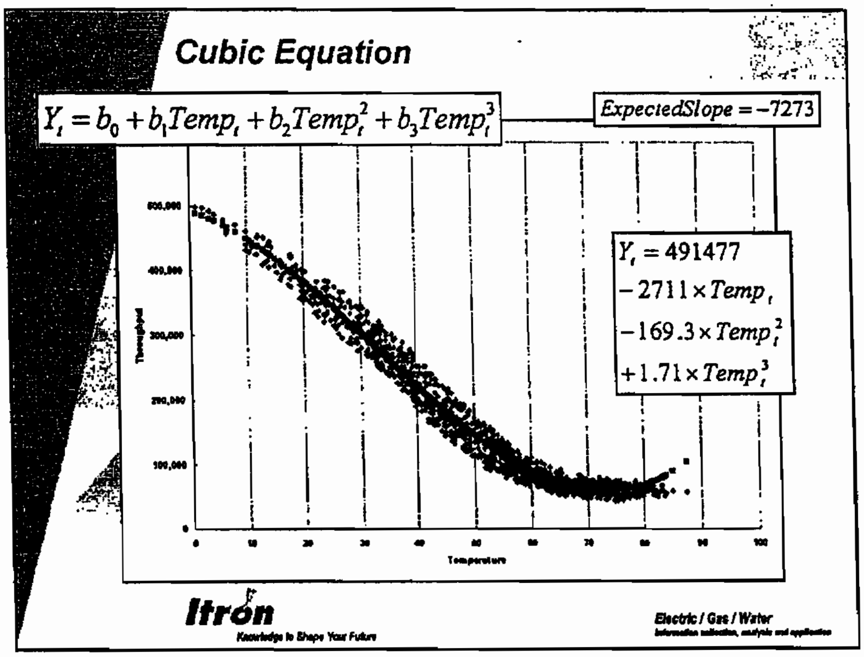

Cubic Equation
$Y_t = b_0 + b_1 Temp_t + b_2 Temp_t^2 + b_3 Temp_t^3$
$ExpectedSlope = -7273$
$Y_t = 491477$
$-2711 \times Temp_t$
$-169.3 \times Temp_t^2$
$+1.71 \times Temp_t^3$
400,000
300,000
200,000
100,000
0
Temperature
Throughput
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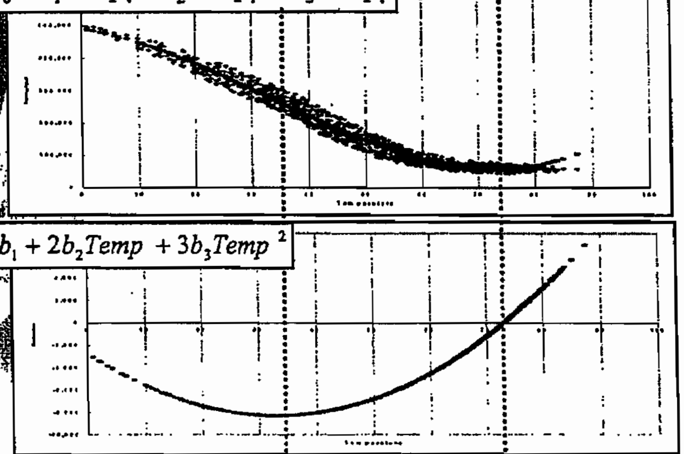
Cubic Derivative

$$Y_t = b_0 + b_1 Temp_t + b_2 Temp_t^2 + b_3 Temp_t^3$$

$$ExpectedSlope = -7273$$

$$Y_t' = b_1 + 2b_2 Temp + 3b_3 Temp^2$$



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Logit Model Form

Specific Form:

$$Y^t = B_0 + B_1 \times H_1^t + B_2 \times H_2^t + u^t$$

where:

$$H_1^t = \frac{1}{1 + e^{-(a_0 + a_1 Temp_t)}}$$

$$H_2^t = \frac{1}{1 + e^{-(b_0 + b_1 Temp_t)}}$$

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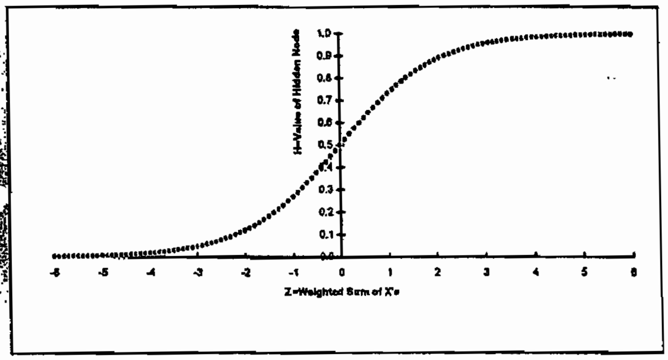
Binary Logistic (Logit) Function

$$H_1^t = \frac{1}{1+e^{-\left(a_0+a_1 Temp_t\right)}} \Rightarrow \frac{1}{1+e^{-Z}}$$



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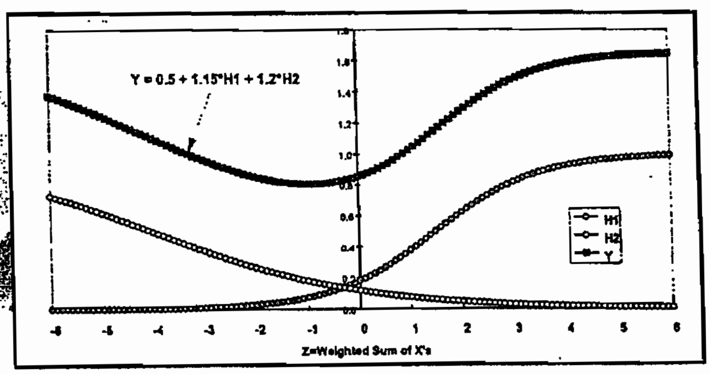
Flexible Nonlinearities

$$Y^t = B_0 + B_1 \times H_1^t + B_2 \times H_2^t$$



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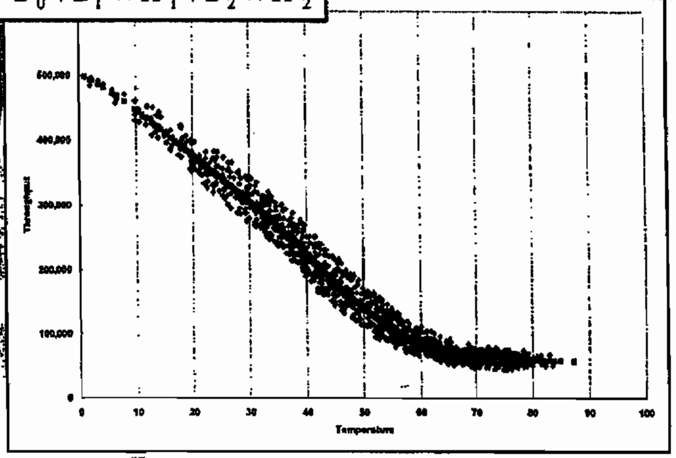
Logit Model Form Equation

$$Y^t = B_0 + B_1 \times H_1^t + B_2 \times H_2^t$$

$ExpectedSlope = -7273$



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Derivatives – Basics

$$\frac{d(bX)}{dX} = b$$

$$\frac{d(N(X)/D(X))}{dX} = \frac{D \times N' - N \times D'}{D^2}$$

$$\frac{d(e^X)}{dX} = e^X$$

$$\frac{d\left(\frac{1}{1+e^{-bX}}\right)}{dX} = \frac{0 + b \times e^{-bX}}{(1+e^{-bX})^2}$$

$$\frac{d(e^{bX})}{dX} = be^{bX}$$

$$\frac{d\left(\frac{1}{1+e^{-bX}}\right)}{db} = \frac{0 + X \times e^{-bX}}{(1+e^{-bX})^2}$$

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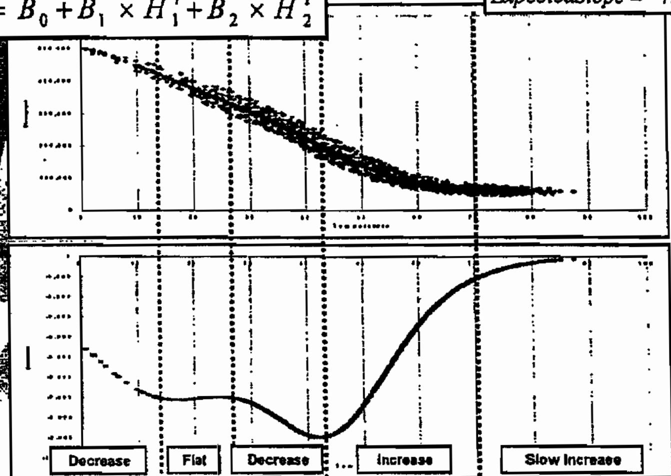
Logit Model Temperature Derivative

$$Y^t = B_0 + B_1 \times H_1^t + B_2 \times H_2^t$$

$ExpectedSlope = -7273$



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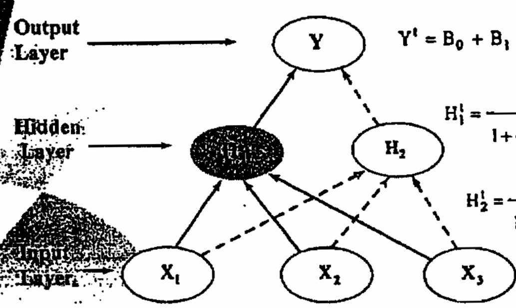
Neural Network

General Form $$Y^t = G\left(B_0 + \sum_{n=1}^{2} B_n \times H_n\left(X_1^t, X_2^t, X_3^t\right)\right)$$



$$Y^t = B_0 + B_1 \times H_1^t + B_2 \times H_2^t + u^t$$

$$H_1^t = \frac{1}{1+e^{-(a_0+a_1X_1^t+a_2X_2^t+a_3X_3^t)}}$$

$$H_2^t = \frac{1}{1+e^{-(b_0+b_1X_1^t+b_2X_2^t+b_3X_3^t)}}$$

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In-Sample Fit Statistics

Akaike's Information Criterion

$$AIC(k) = \frac{2k}{N} + LOG\left(\frac{SSE}{N}\right)$$

Bayesian Information Criterion

$$BIC(k) = \frac{k\,LOG(N)}{N} + LOG\left(\frac{SSE}{N}\right)$$

Mean Absolute Percentage Error

$$MAPE = \frac{\sum_{t=1}^{N}\left|\hat{e}_t / y_t\right|}{N} \times 100$$

Coefficient of Determination (R^2):

$$R^2 = 1 - SSE/TSS$$

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Relative Accuracy of Forms

Model	R-Sq	MAPE	AIC	BIC
Temp	0.91	26.30%	20.72	20.73
HDD	0.97	12.26%	19.69	19.70
Bins	0.96	12.15%	20.05	20.08
PWL	0.98	9.86%	19.40	19.42
Quad	0.96	13.56%	19.89	19.90
Cubic	0.98	10.93%	19.45	19.47
NN	0.98	9.85%	19.37	19.39

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Agenda

Examine building a daily throughput forecast model

Topics

1. **Regression Basics**
2. **Load Weather Relationship**
3. **Wind Impacts**
4. **Yesterday's Temperature Impacts**

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Wind Impacts

Use Wind Chill Index

35.74 +0.6215(Temp) - 35.75($WS^{0.16}$)+ 0.4275(Temp)($WS^{0.16}$)

- NOAA definition effective November 2001.
  Wind Chill Temperature is only defined for temperatures at or below 50 degrees F and wind speeds above 3 mph.

Model Wind Separately

$$Y_t = b_0 + b_1 S_{1,t} + b_2 S_{2,t} + b_3 S_{3,t} + b_4 W_t$$

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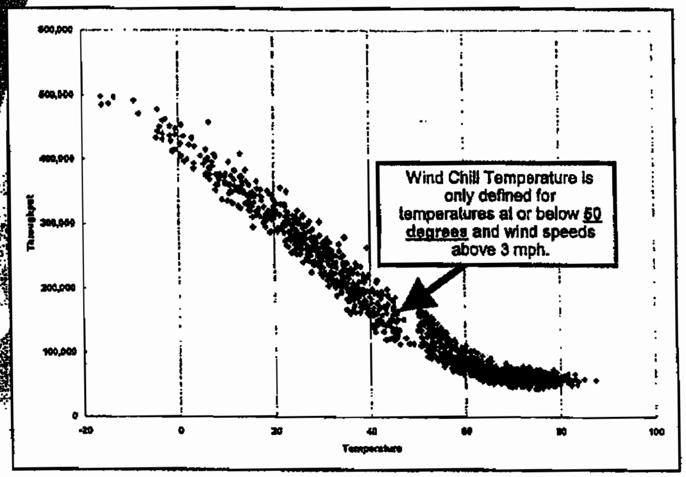
Throughput/Wind Chill Relationship



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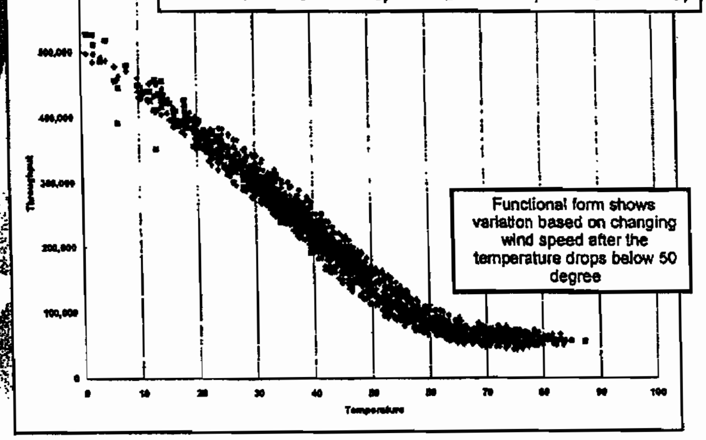
PWL Using Wind Chill - Form

$$Y_t = b_0 + b_1 WCS_{1,t} + b_2 WCS_{2,t} + b_3 WCS_{3,t}$$



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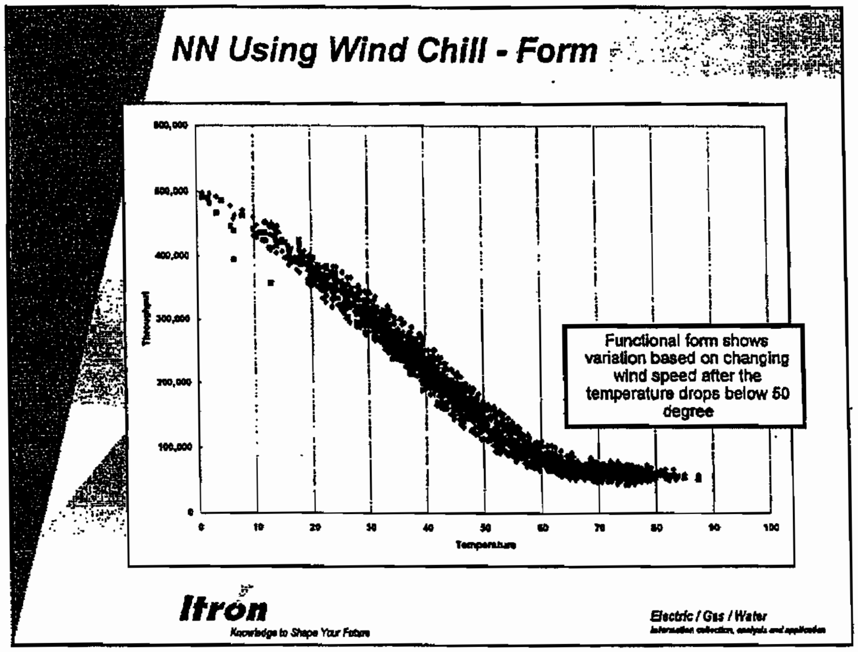
NN Using Wind Chill - Form
600,000
500,000
400,000
300,000
200,000
100,000
0
0
10
20
30
40
50
60
70
80
90
100
Temperature
Functional form shows variation based on changing wind speed after the temperature drops below 50 degree
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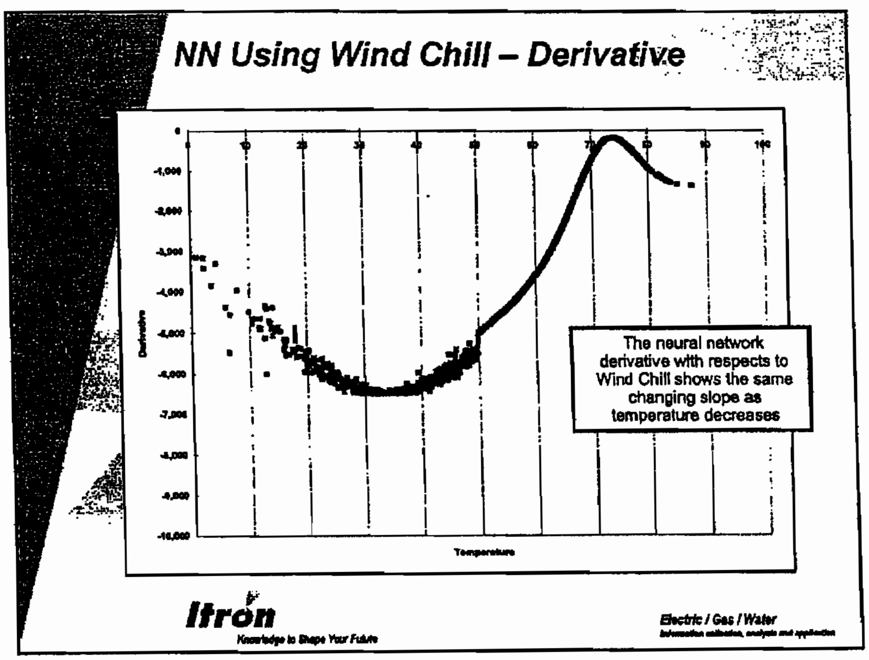
NN Using Wind Chill – Derivative
Derivative
Temperature
The neural network derivative with respects to Wind Chill shows the same changing slope as temperature decreases
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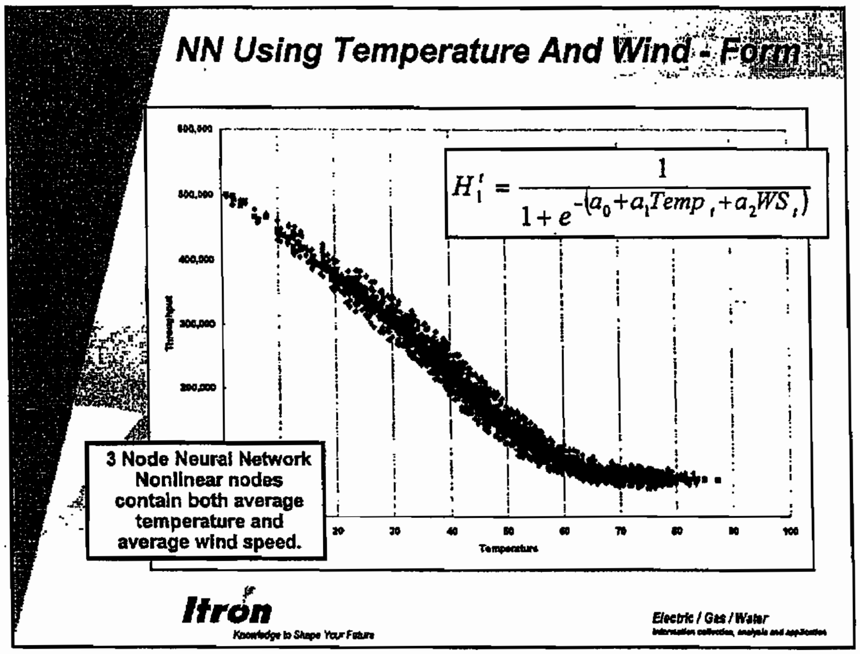
NN Using Temperature And Wind - Form
$H_1^t = \frac{1}{1+e^{-(a_0 + a_1 Temp_t + a_2 WS_t)}}$
3 Node Neural Network
Nonlinear nodes contain both average temperature and average wind speed.
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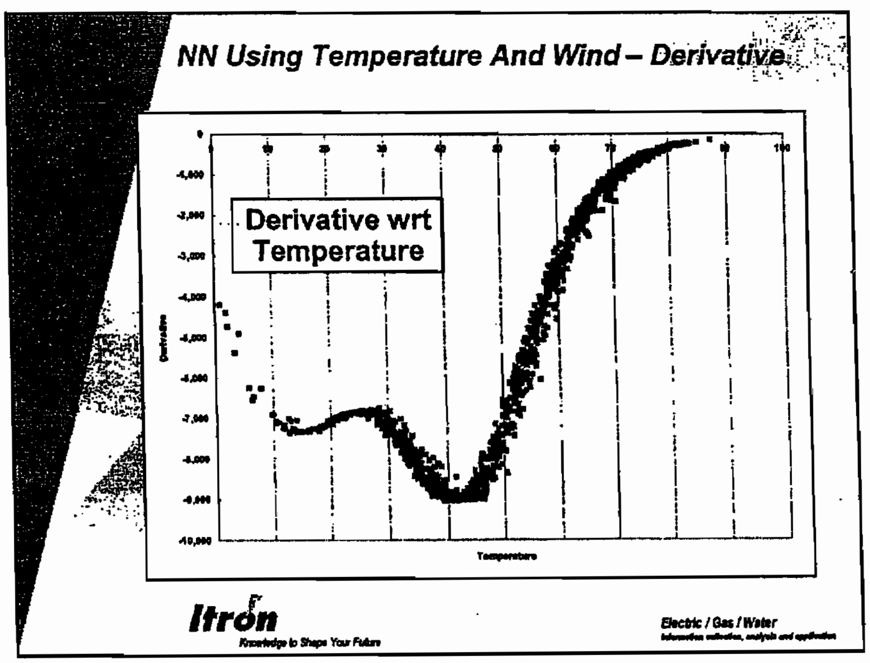
NN Using Temperature And Wind – Derivative
Derivative wrt Temperature
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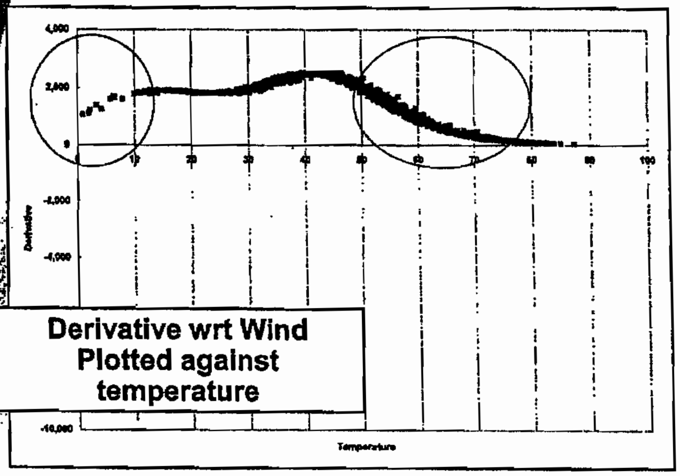
NN Using Temperature And Wind – Derivative



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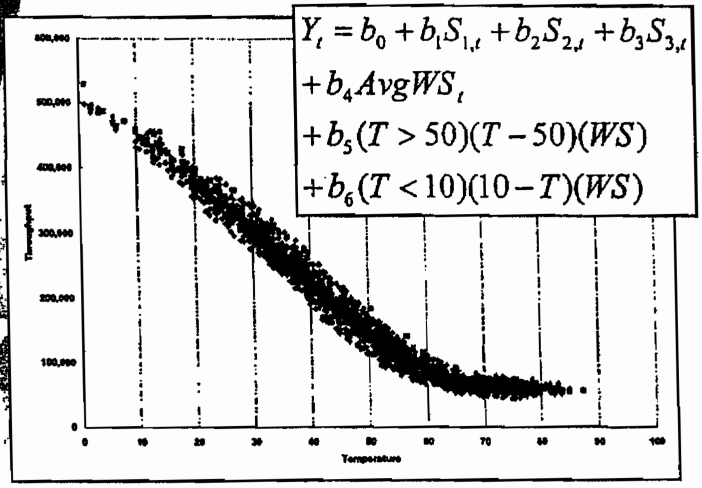
PWL Wind Separate



$$Y_t = b_0 + b_1 S_{1,t} + b_2 S_{2,t} + b_3 S_{3,t}$$
$$+ b_4 AvgWS_t$$
$$+ b_5 (T > 50)(T - 50)(WS)$$
$$+ b_6 (T < 10)(10 - T)(WS)$$

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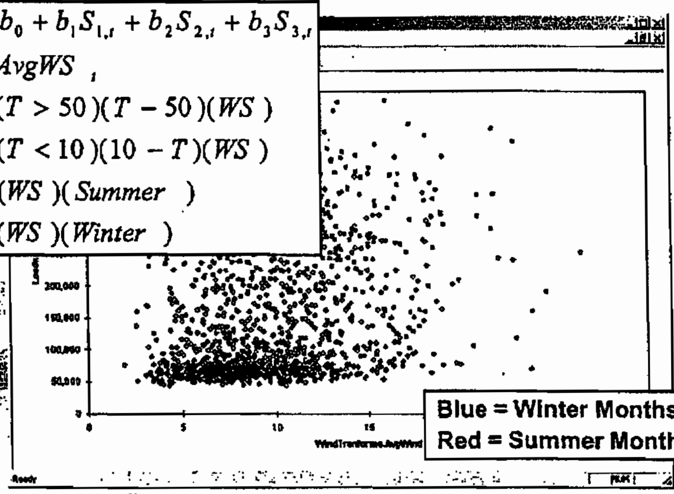
Scatter Plot – Wind Vs. Throughput

$$
\begin{aligned}
Y_t &= b_0 + b_1 S_{1,t} + b_2 S_{2,t} + b_3 S_{3,t} \\
&+ b_4 AvgWS_t \\
&+ b_5 (T > 50)(T - 50)(WS) \\
&+ b_6 (T < 10)(10 - T)(WS) \\
&+ b_7 (WS)(Summer) \\
&+ b_8 (WS)(Winter)
\end{aligned}
$$



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PWL Wind Separate

Model Wind Chill

	R-Sq	MAPE	AIC	BIC
PWL	0.98	9.71%	19.38	19.39
NN	0.98	9.70%	19.35	19.38

Model Wind Separately

	R-Sq	MAPE	AIC	BIC
NN	0.98	9.26%	19.21	19.25
PWL	0.98	9.30%	19.25	19.27
PWL_Seasons	0.98	8.98%	19.18	19.22
NN_Seasons	0.98	8.83%	19.13	19.18

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Agenda

Examine building a daily throughput forecast model

Topics

1. Regression Basics
2. Load Weather Relationship
3. Wind Impacts
4. Yesterday's Temperature Impacts

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Yesterday's Weather

How can we include yesterday's weather into our model?

- 2-Day Average weather
- Exclude yesterday's impact
- Include a separate X variable for yesterday's temperature

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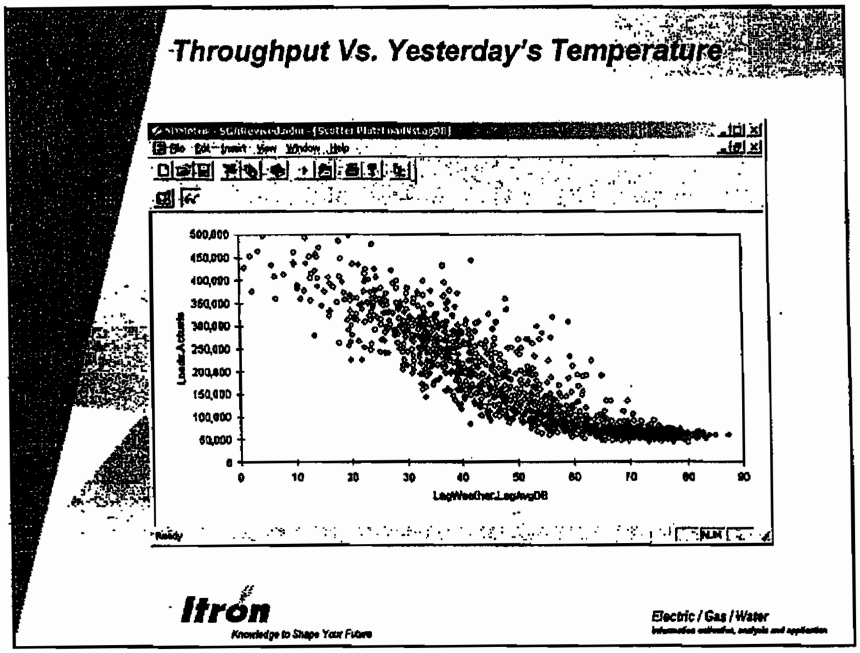
Throughput Vs. Yesterday's Temperature
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
0
10
20
30
40
50
60
70
80
90
Loads.Actuals
LagWeather.LagAvgDB
Ready
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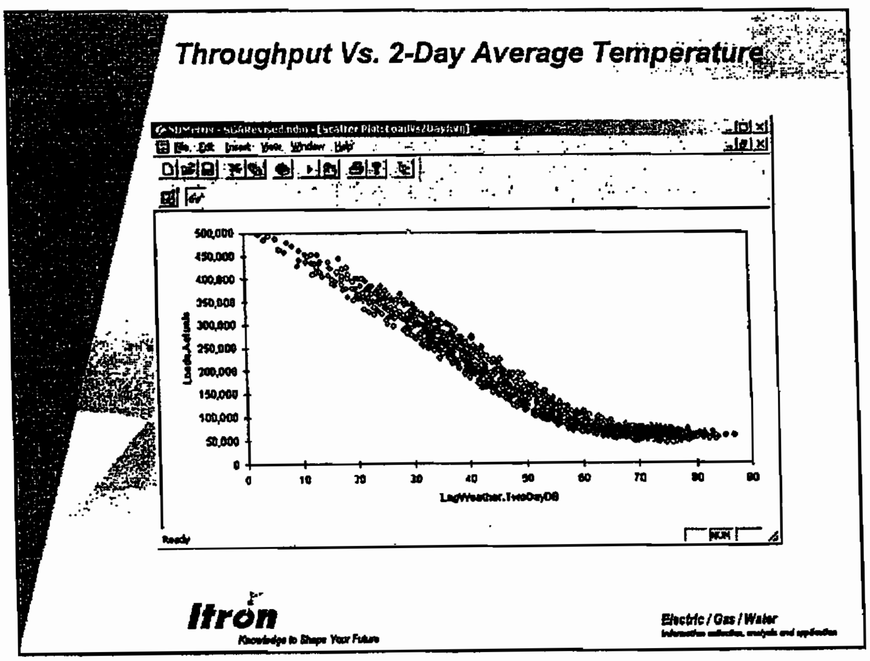
Throughput Vs. 2-Day Average Temperature
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
0
10
20
30
40
50
60
70
80
90
Loads.Actuals
LagWeather.TwoDayDB
Ready
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Yesterday's Weather

2-Day Average Implies a 50/50 weight on today and yesterday's average temperature

MAPEs using a PWL structure

Today/Yesterday		
100/0	9.86%	⟵ **Base Case**
50/50	11.91%	⟵ **Average Case**
75/25	9.92%	
90/10	9.63%	

Hunting for a better balance shows that a blend is better

Model Yesterday Separately

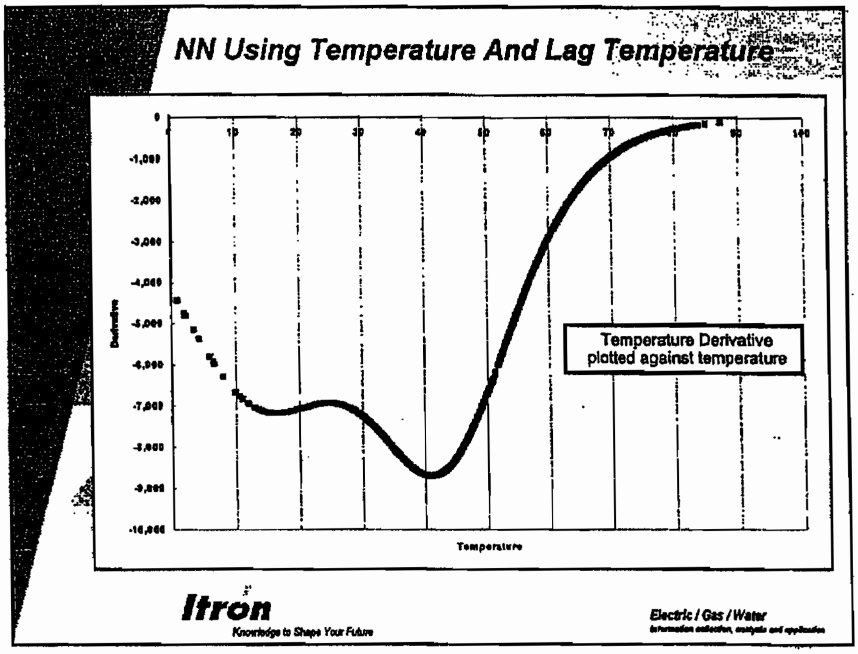
$$Y_t = b_0 + b_1S_{1,t} + b_2S_{2,t} + b_3S_{3,t} + b_4LS_{1,t} + b_5LS_{2,t} + b_6LS_{3,t}$$

Where
S1 = (Temp >= 65)*(Temp-65)
S2 = (55 >= Temp)*(Temp < 65) *(Temp-65) +(Temp <= 55)*(-10)
S3 = (Temp <= 55)*(Temp-55)

Coefficients	
S1	-311.6
S2	-3139.4
S3	-7481.5
LS1	-148.7
LS2	-890.3
LS3	-333.3
MAPE	9.62%

Implies different weights for each spline segment.

S1 = 68%	**LS1 = 32%**
S2 = 78%	**LS2 = 22%**
S3 = 96%	**LS3 = 4%**


NN Using Temperature And Lag Temperature
Derivative
Temperature
Temperature Derivative plotted against temperature
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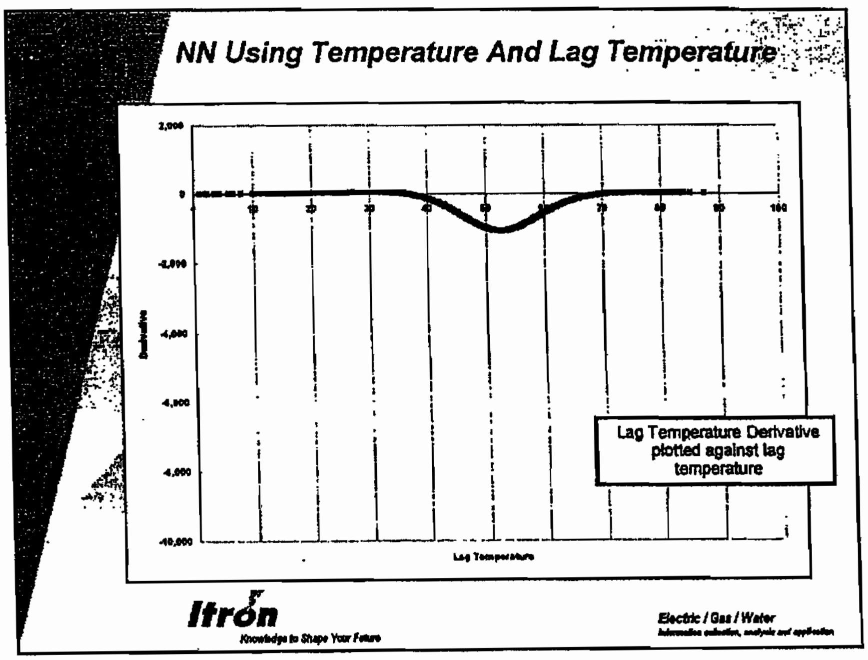
NN Using Temperature And Lag Temperature
Derivative
Lag Temperature
Lag Temperature Derivative plotted against lag temperature
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Yesterday Temperature Impact

Model 2-Day Average

	R-Sq	MAPE	AIC	BIC
PWL 100/0	0.98	9.86%	19.40	19.42
2 Day 50/50	0.95	11.91%	20.26	20.27
2 Day 90/10	0.98	9.63%	19.40	19.41
NN 90/10	0.98	9.64%	19.37	19.40

Model Yesterday Separately

	R-Sq	MAPE	AIC	BIC
PWL	0.98	9.62%	19.38	19.40
NN	0.98	9.50%	19.34	19.39

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Question:

Please explain why the entries for the cubic spline variable in the file "Schedule 30C Cubic Spline Variable.xls" differ from the entries in the file "CGC MCF Data (FPW).xls."

Response:

The entries for the cubic spline variable in the file "CGC MCF Data (FPW).xls" are calculated on the actual weather for each historical month listed, while the entries for the cubic spline variable in the file "Schedule 30C Cubic Spline Variable.xls" are calculated on 30-year normal weather (for the 30 years ending 2005). Please see the Company's response to TRA DR 59 for the method by which the cubic spline variable is calculated.

Question:

As discussed on page 12 of the pre-filed direct testimony of Philip Buchanan, provide all data and calculations supporting the statement, "the base temperature that was found to have the highest correlation with actual usage was 65° F."

Response:

Mr. Buchanan's testimony actually states that "Although the base temperature that was found to have highest correlation with actual usage was 65°F, the base temperature of 55°F also had a high correlation with actual usage. Therefore, both base 65°F and base 55°F were incorporated into the multiple regression models."

When running the regression with only the HDDs as the independent variable and use per customer as the dependant variable the results are as follows:

Using 65 as a base temperature:
R-square .9531
Forecast Error 3.63%
Mean Average Percent Error: 41.87%

Using 55 as a base temperature:
R-square .8235
Forecast Error 7.05%
Mean Average Percent Error: 60.61%

The R-Square, Forecast Error and MAPE are better when using 65 as a base temperature.

The average of a 20 point rolling correlation between consumer usage and HDDs using 55 as a base temperature is .9825 and using 65 as a base temperature is .9975. Actual correlation over the time period is .9795 using 55 as a base and .9942 using 65 as a base.

Because heating degree days calculated on a base temperature of 65 yielded a better regression fit, it was used instead of heating degree days based on other base temperatures. Heating degree days calculated on a base temperature of 55 were used to modify a trend variable in the residential consumption equation, thus it was noted in Mr. Buchanan's testimony to further clarify the revenue forecast model.

Question:

What criteria were used to specify the residential and commercial consumption equations?

a. Please describe all statistical model specification tests employed on the residential and commercial consumption equations.

b. As part of this answer, provide all results and data used to calculate comparative models used in such specification testing.

c. Provide any analysis done to test for multi-collinearity among variables in the forecast model.

d. As referenced on pages 9-10 of the pre-filed direct testimony of Philip Buchanan, provide the results of review of output statistics, backcasting, and holdout period analysis.

Response:

The basic criteria used to specify the residential and commercial consumption equations are that 1.) proven forecasting techniques, such as regression analysis, are used, 2.) proper historical data is used, 3.) all variables used in the regression analysis make logical sense, and 4.) the results of the equations are just and reasonable. Statistical tests for each variable and the results of the equations are performed by Forecast Pro and the results are reviewed by the Company. Common sense analysis of the variables are also performed by the Company to ensure the proper use of variables, such as reasonableness checks on the mathematical signs (positive and negative) of the coefficients of each variable make logical sense.

Response Part a.
Forecast Pro performs statistical tests on each variable as well as the regression analysis in total. For each variable, the Standard Error, t-Statistic, Significance is tested. The results of each test can be seen on the Company's Exhibit PGB-4.

Standard Error: Measures the extent to which each individual observation in a sample differs from the value predicted by the regression. The smaller the standard error in relation to the size of the estimate, the more reliable the estimate.
t-Statistic: The t statistic is a measure of how extreme a statistical estimate is. There is an indication that the hypothesized value is reasonable when the t-statistic is close to zero. Alternately, there is an indication that the hypothesized value is not large enough when the t-statistic is large positive. Finally, there is an indication that the hypothesized value is too large when the t-statistic is large negative.
Significance: The probability that a result is not likely to be due to chance alone.

Tests performed on the regression analysis include the following:
R-Square: the proportion of variation explained by the model.
Adjusted R-Square: a modification of R^2 that adjusts for the number of explanatory terms in a model. – R square is adjusted to account for only adding variables to a model in order to achieve a better R square number.
Durbin-Watson: a statistic used to test for the presence of first-order autocorrelation in the residuals of a regression equation. The test compares the residual for time period t with the residual from time period t-1 and develops a statistic that measures the significance of the correlation between these successive comparisons. The statistic is used to test for the presence of both positive and negative correlation in the residuals.
Forecast Error: The arithmetic mean of the forecast errors, or the exponentially smoothed forecast error. Usually associated with demand forecasting techniques.
MAPE: mean absolute percentage error is the mean of the absolute errors.
Forecast error is a measure of the difference between a forecast and the corresponding verification from analysis or observations.
Ljung-Box: a test for serial correlation in a time series, not just of one period back but of many.
RMSE: The Root Mean Squared Error is the distance, on average, of a data point from the fitted line, measured along a vertical line. The smaller the RMSE, the closer the fit is to the data.

Response Part b.
Some variables, such as heating degree days at different base temperatures, were tested in the equation models, but were not included in the final equations as the test results did not contribute to the overall accuracy of the model. Forecast Pro allows such testing of variables to be performed quickly, with testing results available immediately following the regression. As a result, the Company did not keep results of the regressions that did not pass acceptable test result criteria. The data from which all regressions and equations were developed are included in the file labeled "CGC MCF Data (FPW).xls" as filed in response to TRA DR 30.

Response Part c.

The Forecast Pro application used to evaluate these regressions automatically tests for multi-collinearity present in the regressions, giving an error message when muti-collinearity is detected. The error message was not seen when running these regressions, therefore the Company assumes that multi-collinearity is not present.

Response Part d.
The output statistics and results of backcasting can be seen in the Company's Exhibit PGB-4. The results of the holdout period tests are attached as Schedule TRA DR 62b.

Residential Model
30 month holdout period

Forecast Model for RSAC
Regression(6 regressors 0 lagged errors)

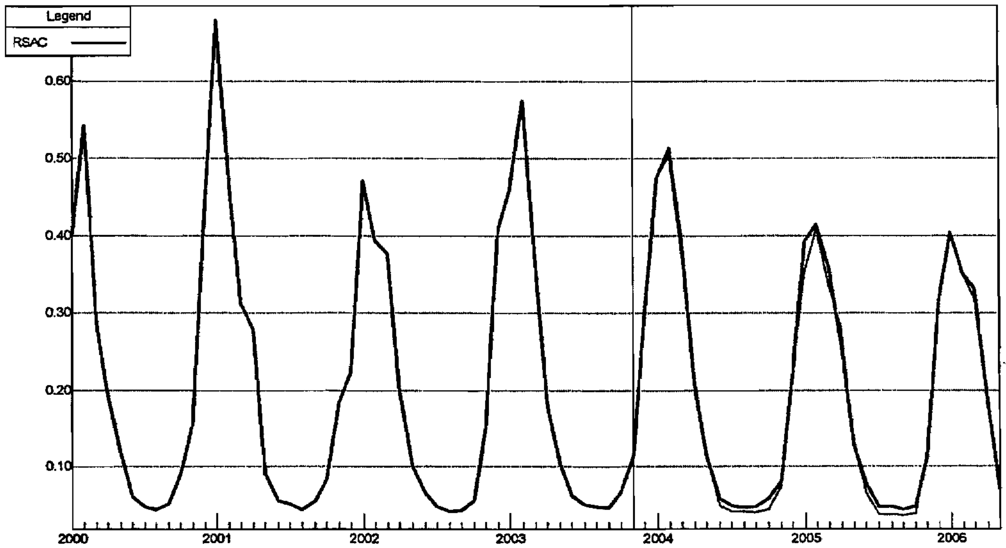
Term	Coefficient	Std. Error	t-Statistic	Significance
SDD65MRD	0.021922	0.000722	30.356736	1
KNOT5565	0.000021	0.000005	3.801038	0.999518
_TSDD	-0.000042	0.00002	-2.143673	0.961808
_PSDD	-0.000281	0.000088	-3.178129	0.997143
CGCTRD	-0.000305	0.000125	-2.44289	0.980919
_CONST	0.036849	0.005887	6.259691	1

Within-Sample Statistics

Sample size	46	Number of parameters	6
Mean	0.1952	Standard deviation	0.1762
R-square	0.9974	Adjusted R-square	0.9971
Durbin-Watson	1.959	Ljung-Box(18)=14.14	P=0.2801
Forecast error	0.95%	BIC	0.01137
MAPE	6.31%	RMSE	0.008854
MAD	0.006846		

Out-of-Sample Rolling Evaluation

H	N	MAD	Cumulative Average	MAPE	Cumulative Average	GMRAE	Cumulative Average
1	30	0.0091	0.0091	0.0830	0.0830	0.1770	0.1770
2	29	0.0093	0.0092	0.0850	0.0840	0.0930	0.1290
3	28	0.0095	0.0093	0.0880	0.0850	0.0620	0.1020
4	27	0.0095	0.0093	0.0910	0.0870	0.0430	0.0830
5	26	0.0093	0.0093	0.0930	0.0880	0.0330	0.0700
6	25	0.0093	0.0093	0.0950	0.0890	0.0400	0.0640
7	24	0.0096	0.0094	0.0980	0.0900	0.0370	0.0600
8	23	0.0096	0.0094	0.0960	0.0910	0.0430	0.0580
9	22	0.0097	0.0094	0.0930	0.0910	0.0470	0.0570
10	21	0.0099	0.0095	0.0910	0.0910	0.0900	0.0590
11	20	0.0101	0.0095	0.0890	0.0910	0.1960	0.0640
12	19	0.0099	0.0095	0.0800	0.0900	0.2520	0.0700
13	18	0.0101	0.0096	0.0810	0.0900	0.1420	0.0730
14	17	0.0101	0.0096	0.0820	0.0890	0.0690	0.0730
15	16	0.0084	0.0095	0.0820	0.0890	0.0420	0.0710
16	15	0.0086	0.0095	0.0860	0.0890	0.0360	0.0690
17	14	0.0077	0.0094	0.0880	0.0890	0.0230	0.0660
18	13	0.0067	0.0093	0.0890	0.0890	0.0350	0.0650
19	12	0.0073	0.0093	0.0960	0.0890	0.0300	0.0630
20	11	0.0067	0.0092	0.0890	0.0890	0.0250	0.0620
21	10	0.0064	0.0091	0.0770	0.0890	0.0270	0.0610
22	9	0.0059	0.0091	0.0620	0.0880	0.0390	0.0600
23	8	0.0057	0.0090	0.0480	0.0870	0.0470	0.0600
24	7	0.0052	0.0089	0.0270	0.0860	0.1060	0.0600
25	6	0.0053	0.0089	0.0240	0.0860	0.0190	0.0590
26	5	0.0053	0.0089	0.0260	0.0850	0.0130	0.0580
27	4	0.0064	0.0088	0.0320	0.0840	0.0190	0.0580
28	3	0.0084	0.0088	0.0420	0.0840	0.0320	0.0580
29	2	0.0054	0.0088	0.0410	0.0840	0.0360	0.0570
30	1	0.0027	0.0088	0.0390	0.0840	0.0610	0.0570
			0.0079		7.31%		6.38%



Note that the GMRAE is the Geometric Mean Relative Absolute Error. It is the ratio of the mean absolute error of this model versus the absolute error of a naïve model at a specific horizon length (H). The naïve model forecast equals the last historical data point. For example a GMRAE of .295 indicates that the size of the current model's error is only 29.5% of the size of the error generated using the naïve model for the same data set. The GMRAE is a good statistics to use when comparing the performance of different methods across different times series.

Good fit for the model with a holdout of 30 months.

Commercial Model
12 Month Holdout Period

Forecast Model for CSAC
Regression(4 regressors, 0 lagged errors)

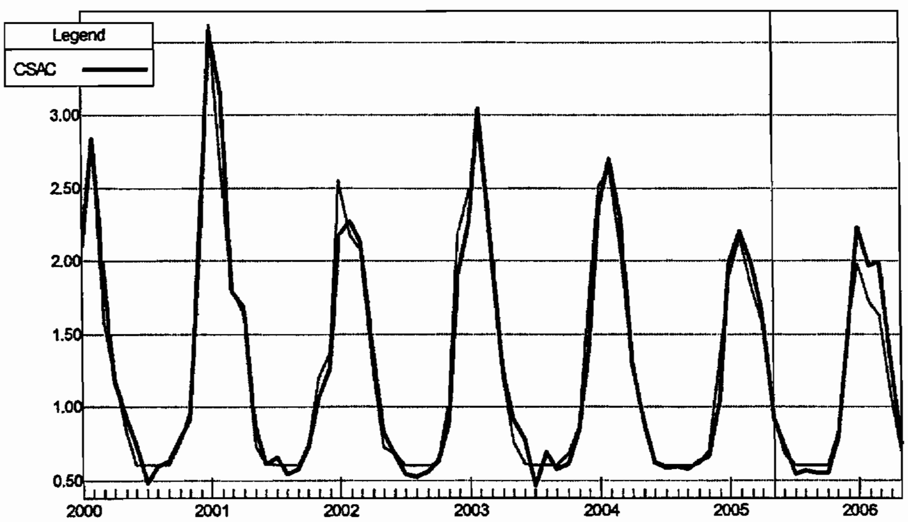
Term	Coefficient	Std. Error	t-Statistic	Significance
SDD65MRD	0.098584	0.003889	25.347889	1
KNOT5565	0.00015	0.000069	2.192451	0.967763
_TSDD	-0.000041	0.00001	-3.99213	0.999819
_CONST	0.452818	0.05541	8.172201	1

Within-Sample Statistics

Sample size	64	Number of parameters		4
Mean	1.285	Standard deviation		0.7944
R-square	0.9684	Adjusted R-square		0.9668
Durbin-Watson	1.748	** Ljung-Box(18)=42.49	P=0.9991	
Forecast error	0.1448	BIC		0.1596
MAPE	0.08102	RMSE		0.1402
MAD	0.09633			

Out-of-Sample Rolling Evaluation

H	N	MAD	Cumulative Average	MAPE	Cumulative Average	GMRAE	Cumulative Average
1	12	0.123403	0.123403	0.099	0.099	0.629	0.629
2	11	0.130075	0.126594	0.102	0.1	0.342	0.47
3	10	0.13721	0.129811	0.101	0.1	0.212	0.37
4	9	0.149016	0.133926	0.106	0.102	0.156	0.307
5	8	0.161181	0.138287	0.108	0.103	0.167	0.279
6	7	0.176739	0.143009	0.11	0.103	0.232	0.272
7	6	0.199325	0.148373	0.119	0.105	0.169	0.26
8	5	0.236041	0.154819	0.141	0.108	0.259	0.26
9	4	0.232865	0.159155	0.148	0.11	0.307	0.263
10	3	0.225728	0.161818	0.154	0.112	0.368	0.266
11	2	0.156577	0.161682	0.14	0.112	1.515	0.278
12	1	0.074236	0.16056	0.098	0.112	0.455	0.28



18 Month Holdout Period

Forecast Model for CSAC
Regression(4 regressor 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
SDD65MRD	0.099657	0.004323	23.052334	1
KNOT5565	0.000138	0.000071	1.941611	0.942591 <-
_TSDD	-0.000052	0.000014	-3.652036	0.999411
_CONST	0.464374	0.058027	8.002663	1

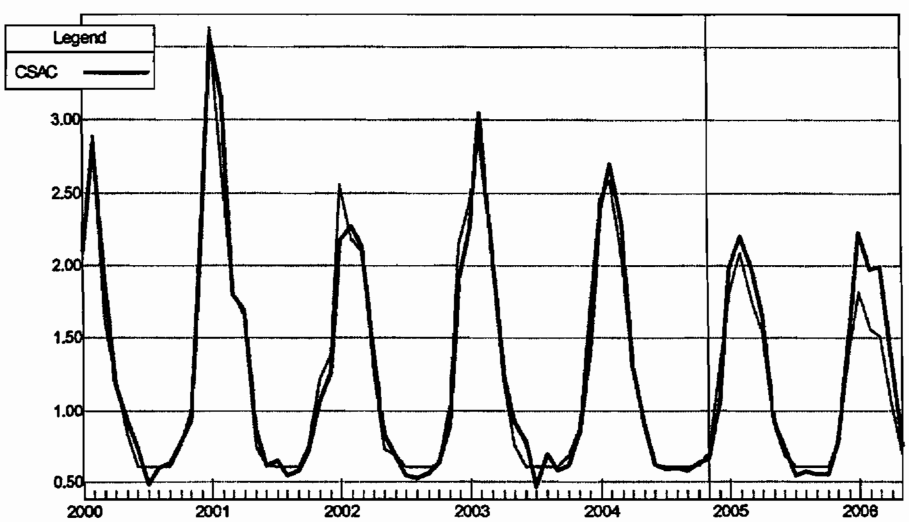
Marked regressors are insignificant.

Within-Sample Statistics

Sample size	58	Number of parameters	4
Mean	1.249	Standard deviation	0.8115
R-square	0.97	Adjusted R-square	0.9684
Durbin-Watson	1.776	* Ljung-Box(18)=33.86 P=0.9869	
Forecast error	0.1443	BIC	0.1602
MAPE	0.08182	RMSE	0.1393
MAD	0.09652		

Out-of-Sample Rolling Evaluation

H	Cumulative N	Cumulative MAD	Cumulative Average	MAPE	Average	GMRAE	Average
1	18	0.162861	0.162861	0.113	0.113	0.518	0.518
2	17	0.158256	0.160624	0.106	0.11	0.322	0.411
3	16	0.157319	0.159587	0.108	0.109	0.156	0.303
4	15	0.160054	0.159693	0.111	0.11	0.109	0.24
5	14	0.155611	0.158979	0.111	0.11	0.112	0.21
6	13	0.158526	0.158916	0.114	0.111	0.125	0.196
7	12	0.170271	0.160214	0.122	0.112	0.118	0.185
8	11	0.181001	0.162185	0.127	0.113	0.143	0.18
9	10	0.193315	0.164655	0.129	0.115	0.166	0.179
10	9	0.211451	0.167775	0.137	0.116	0.26	0.184
11	8	0.23153	0.171342	0.143	0.118	1.202	0.204
12	7	0.257287	0.175353	0.15	0.119	0.874	0.218
13	6	0.299536	0.180129	0.175	0.121	0.707	0.228
14	5	0.334592	0.184926	0.193	0.123	0.661	0.236
15	4	0.316708	0.188121	0.196	0.125	0.251	0.236
16	3	0.286359	0.189875	0.192	0.126	0.301	0.237
17	2	0.189359	0.189869	0.188	0.127	0.361	0.239
18	1	0.083275	0.189245	0.11	0.127	0.928	0.241



Commercial 2

Comm 2 with 12 months holdout

Forecast Model for C2AC
Regression(4 regressors 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance	
SDD72MRD	0.328327	0.033656	9.755425	1	
KNOT5572	0.000341	0.000082	4.157657	0.999803	
_PSDD	-0.008168	0.004611	-1.771522	0.914819	<-
_CONST	1.034023	0.321875	3.212494	0.997177	

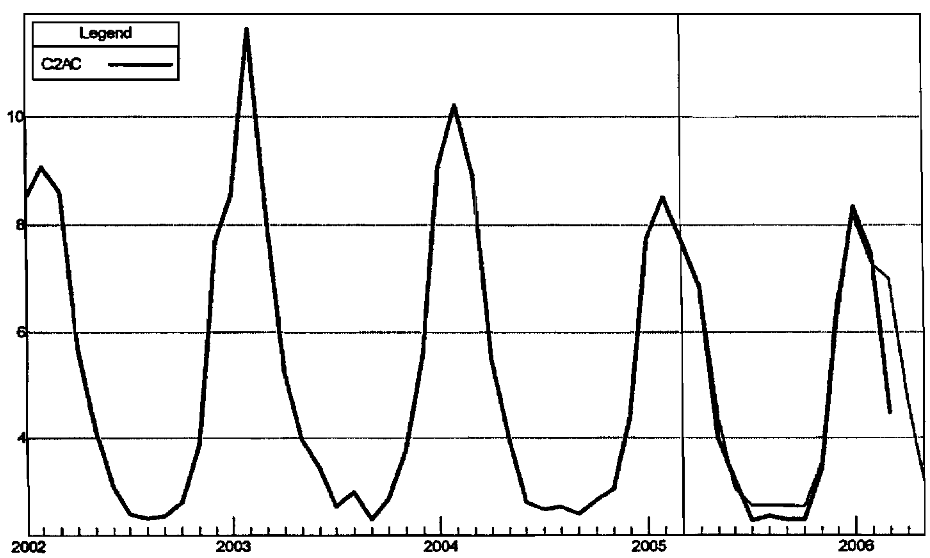
Marked regressors are insignificant.

Within-Sample Statistics

Sample size	39	Number of parameters	4
Mean	5.253	Standard deviation	2.755
R-square	0.9635	Adjusted R-square	0.9603
Durbin-Watson	1.616	Ljung-Box(18)=37.12 P=0.9949	
Forecast error	54.87%	BIC	0.6272
MAPE	7.61%	RMSE	0.5198
MAD	0.3934		

Out-of-Sample Rolling Evaluation

Cumulative H	Cumulative N	Cumulative MAD	Average	MAPE	Average	GMRAE	Average
1	12	0.414085	0.414085	0.106	0.106	0.442	0.442
2	11	0.442958	0.427894	0.114	0.11	0.264	0.345
3	10	0.442871	0.432432	0.114	0.111	0.167	0.277
4	9	0.472521	0.441023	0.121	0.113	0.115	0.229
5	8	0.496054	0.449828	0.121	0.114	0.114	0.205
6	7	0.53926	0.460811	0.127	0.116	0.097	0.187
7	6	0.585206	0.472658	0.131	0.117	0.084	0.173
8	5	0.655	0.486065	0.138	0.119	0.129	0.17
9	4	0.782853	0.502554	0.161	0.121	0.219	0.172
10	3	0.952575	0.520554	0.201	0.124	0.716	0.182
11	2	1.342822	0.541912	0.291	0.129	0.983	0.19
12	1	2.494215	0.566942	0.556	0.134	0.776	0.194



Commercial -2 with 24 Month Holdout Period

Forecast Model for C2AC
Regression(4 regressors 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
SDD72MRD	0.3253	0.0438	7.4332	1.0000
KNOT5572	0.0003	0.0001	2.7576	0.9888
_PSDD	-0.0087	0.0061	-1.4121	0.8287 <-
_CONST	1.2127	0.4268	2.8412	0.9908

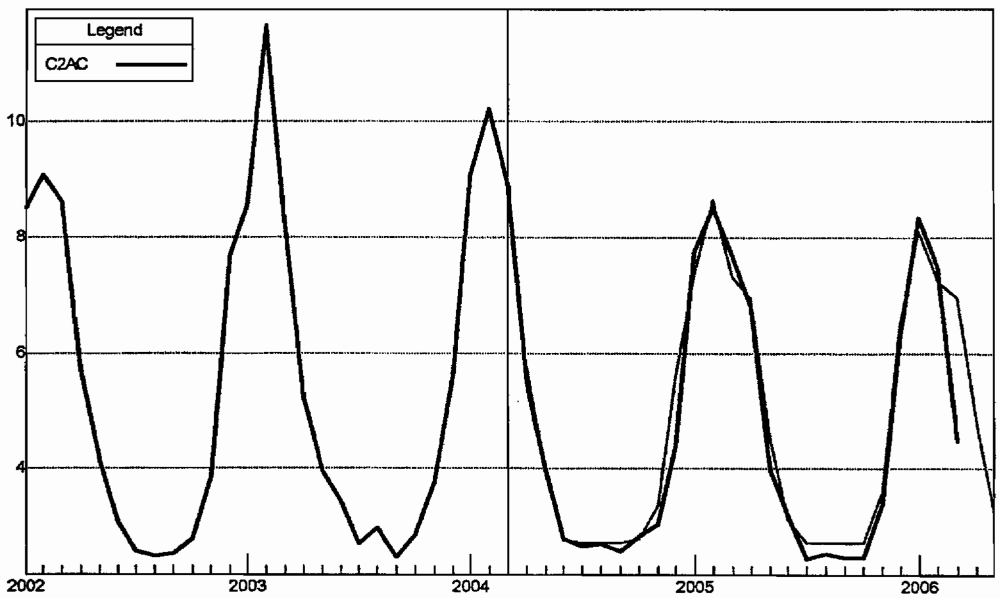
Marked regressors are insignificant.

Within-Sample Statistics

Sample size	27	Number of parameters		4
Mean	5.576	Standard deviation		2.927
R-square	0.9609	Adjusted R-square		0.9558
Durbin-Watson	1.404	Ljung-Box(18)=28.04	P=0.9386	
Forecast error	61.50%	BIC		0.7246
MAPE	8.32%	RMSE		0.5676
MAD	0.4469			

Out-of-Sample Rolling Evaluation

Cumulative H	Cumulative N	Cumulative MAD	Average	MAPE	Average	GMRAE	Average
1	24	0.34308	0.34308	0.082	0.082	0.344	0.344
2	23	0.346061	0.344539	0.084	0.083	0.217	0.275
3	22	0.359117	0.349187	0.087	0.084	0.126	0.214
4	21	0.374672	0.355134	0.091	0.086	0.099	0.179
5	20	0.390362	0.361539	0.094	0.087	0.094	0.159
6	19	0.409624	0.368621	0.098	0.089	0.087	0.145
7	18	0.423705	0.375366	0.101	0.09	0.097	0.138
8	17	0.446162	0.382705	0.106	0.092	0.121	0.136
9	16	0.454183	0.389058	0.106	0.093	0.147	0.137
10	15	0.404764	0.390266	0.095	0.093	0.25	0.144
11	14	0.405664	0.391298	0.098	0.094	0.465	0.156
12	13	0.426206	0.393342	0.104	0.094	0.736	0.17
13	12	0.431016	0.395274	0.109	0.095	0.383	0.178
14	11	0.457725	0.398078	0.117	0.096	0.214	0.179
15	10	0.449474	0.400093	0.115	0.097	0.217	0.18
16	9	0.489368	0.403137	0.124	0.098	0.144	0.179
17	8	0.51389	0.406394	0.125	0.098	0.115	0.177
18	7	0.56034	0.410257	0.132	0.099	0.113	0.175
19	6	0.610609	0.414475	0.136	0.1	0.104	0.173
20	5	0.681752	0.419083	0.143	0.101	0.135	0.172
21	4	0.798231	0.424241	0.162	0.102	0.165	0.172
22	3	0.987655	0.429932	0.204	0.103	0.631	0.174
23	2	1.362211	0.436168	0.292	0.104	0.663	0.176
24	1	2.476234	0.442969	0.552	0.105	0.561	0.177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Commercial-2 with 30 Month Holdout Period

Forecast Model for C2AC
Regression(4 regressors 0 lagged errors)

Term	Coefficient	Std. error	t-Statistic	Significance
SDD72MRD	0.308245	0.042386	7.272361	0.999999
KNOT5572	0.000232	0.000116	2.003759	0.938701 <-
_PSDD	-0.007454	0.005849	-1.274447	0.780349 <-
_CONST	1.534944	0.468477	3.276454	0.995549

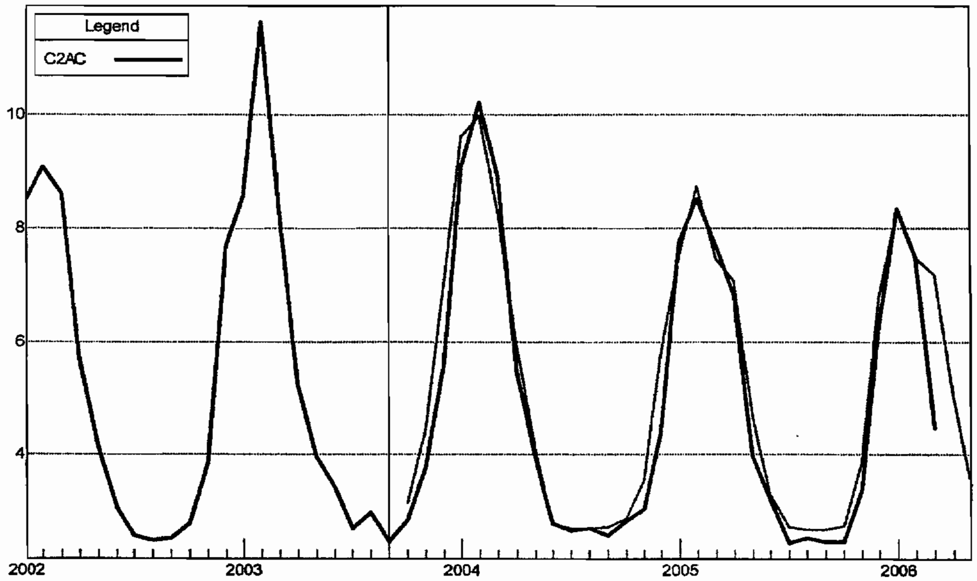
Marked regressors are insignificant.

Within-Sample Statistics

Sample size	size 21	Number of parameters	4
Mean	5.245	Standard deviation	2.869
R-square	0.9657	Adjusted R-square	0.9596
Durbin-Watson	1.821	Ljung-Box(12)=11.97	P=0.5521
Forecast error	57.64%	BIC	0.6931
MAPE	7.30%	RMSE	0.5186
MAD	0.3888		

Out-of-Sample Rolling Evaluation

Cumulative H	Cumulative N	Cumulative MAD	Average	MAPE	Average	GMRAE	Average
1	30	0.433691	0.433691	0.098	0.098	0.275	0.275
2	29	0.437938	0.435778	0.098	0.098	0.17	0.217
3	28	0.42937	0.433716	0.095	0.097	0.085	0.161
4	27	0.392052	0.423848	0.089	0.095	0.065	0.13
5	26	0.386423	0.416898	0.09	0.094	0.053	0.11
6	25	0.392441	0.413192	0.093	0.094	0.049	0.097
7	24	0.3819	0.409219	0.093	0.094	0.049	0.089
8	23	0.379334	0.405976	0.094	0.094	0.06	0.085
9	22	0.389988	0.404473	0.097	0.094	0.07	0.084
10	21	0.408411	0.404798	0.101	0.095	0.138	0.087
11	20	0.427155	0.406424	0.105	0.095	0.24	0.094
12	19	0.449598	0.409214	0.111	0.096	0.615	0.106
13	18	0.466291	0.412507	0.114	0.097	0.318	0.113
14	17	0.491598	0.416593	0.12	0.099	0.165	0.115
15	16	0.490329	0.420013	0.117	0.099	0.134	0.116
16	15	0.430874	0.420466	0.104	0.1	0.077	0.114
17	14	0.445303	0.421395	0.109	0.1	0.065	0.112
18	13	0.461897	0.422756	0.115	0.1	0.073	0.11
19	12	0.480596	0.424495	0.122	0.101	0.07	0.109
20	11	0.499796	0.426516	0.13	0.102	0.085	0.108
21	10	0.4752	0.427675	0.124	0.102	0.084	0.107
22	9	0.520179	0.429615	0.135	0.103	0.214	0.109
23	8	0.548863	0.431799	0.137	0.104	0.213	0.11
24	7	0.604709	0.434525	0.148	0.104	0.399	0.112
25	6	0.667508	0.437631	0.157	0.105	0.732	0.115
26	5	0.745826	0.441018	0.166	0.106	0.07	0.115
27	4	0.808547	0.444221	0.171	0.106	0.047	0.114
28	3	0.910876	0.447251	0.201	0.107	0.035	0.113
29	2	1.345775	0.451124	0.299	0.108	0.05	0.112
30	1	2.68378	0.455925	0.598	0.109	1.321	0.113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Question 63: Please provide a price out in a working Excel file on CD including all formulas with the current customer base using the proposed rate structure absent any revenue deficiency or surplus effect.

Response:

Please refer to attached schedules TRA-63 1, 2, and 3 along with the enclosed CD.

Question:

Provide the number of customers by rate classification, by month, from January 1997 through December 2002.

Response:

Please see the attached Schedule TRA DR 64 for the number of customers by rate class, by month, from January 1998 through December 2002.

The data regarding the number of customers by rate class, by month, from January 1997 through December 1997 and for December 1998 are not readily available. The Company has requested retrieval of those records from the Company's off-site document storage service. Upon receipt, the Company will file an update to TRA DR 64.

CHATTANOOGA GAS COMPANY
CGC Schedule TRA DR 64 NUMBER OF CUSTOMERS
Actuals from January 1998 through December 2002

	RESIDENTIAL	R-4 MULTI-FAMILY	COMMERCIAL	I1	T2	I1/T2	L1/T1	SS1	I1/T2 + T1	L1	T1	T3	SPECIAL CONTRACT
	Customers	Customers	Customers			Customers	Customers	Customers					Customers
Jan-98	47,682	6	8,065	19	17					22	41		
Feb-98	48,007	6	8,118	18	25					21	43		
Mar-98	47,108	6	8,027	19	22					34	35		
Apr-98	47,436	6	8,010	33	3					45	6		
May-98	46,854	6	7,684	13	24					39	35		
Jun-98	46,298	6	7,762	18	16					47	47		
Jul-98	46,099	6	7,683	25	5					52	10		
Aug-98	45,966	6	7,653	22	10					44	32		
Sep-98	46,045	6	7,641	17	17					37	52		
Oct-98	46,342	6	7,636	18	17					37	51		
Nov-98	47,084	6	7,751	13	15					30	51		
Dec-98													
Jan-99	48,925	6	8,196	17	13					36	50		
Feb-99	49,114	6	8,228	16	15					37	50		
Mar-99	49,117	6	8,242	16	14					35	51		
Apr-99	48,923	5	8,160	18	15					34	53		
May-99	48,634	5	8,049	24	1					50	10		
Jun-99	47,995	5	7,887	24	2					51	11		
Jul-99	47,593	5	7,801	21	7					38	28		
Aug-99	45,274	5	7,664	24	3					52	11		
Sep-99	47,579	5	7,728	25	3					50	11		
Oct-99	48,460	5	7,858	15	15					44	52		
Nov-99	47,972	5	7,662			16	56	2					1
Dec-99	48,645	5	7,982			25	47	0					1
Jan-00	49,182	5	8,033			25	47	1					1
Feb-00	49,447	5	8,110			25	47	1					1
Mar-00	49,026	5	8,000			27	47	1					1
Apr-00	49,333	5	8,160			27	47	1					1
May-00	49,917	5	8,085			27	47	2					1
Jun-00	46,259	5	7,829			27	47	2					1
Jul-00	45,452	5	7,469			27	47	4					1
Aug-00	45,552	5	7,281			27	47	3					1
Sep-00	47,876	5	7,695			27	47	1					1
Oct-00	48,274	5	7,727			27	47	2					0
Nov-00	49,295	5	7,859			29	44	3					0
Dec-00	49,988	5	8,076			29	45	1					0
Jan-01	50,522	4	8,205			27	43	2					1
Feb-01	50,650	4	8,291			27	44	1					1
Mar-01	50,682	4	8,271			28	43	3					1
Apr-01	50,445	4	8,231			27	44	3					1
May-01	49,503	3	8,055			28	43	3					1
Jun-01	48,759	4	7,894			28	43	3					1
Jul-01	48,448	4	7,794			27	44	3					1
Aug-01	47,982	5	7,731			28	45	3					1
Sep-01	47,869	4	7,714			28	43	0					1
Oct-01	48,167	4	7,726			27	44	0					1
Nov-01	49,342	4	7,844			28	43	3					1
Dec-01	49,918	4	8,007			28	42	1					1
Jan-02	51,159	4	8,327			27	43	2					1
Feb-02	51,332	4	8,389			27	43	3					1
Mar-02	51,447	4	8,391			26	44	3					1

CHATTANOOGA GAS COMPANY
CGC Schedule TRA DR 64 NUMBER OF CUSTOMERS
Actuals from January 1998 through December 2002

	RESIDENTIAL	R-4 MULTI-FAMILY	COMMERCIAL	I1	T2	I1/T2	L1/T1	SS1	I1/T2 + T1	L1	T1	T3	SPECIAL CONTRACT
Apr-02	51,117	4	8,300			27	43	3					1
May-02	50,526	4	8,141			28	41	3					1
Jun-02	50,005	4	8,035			28	41	3					1
Jul-02	49,701	4	7,945			28	42	3					1
Aug-02	49,349	4	7,889			28	42	3					1
Sep-02	49,275	4	7,885			30	42	3					1
Oct-02	49,800	4	7,916			28	44	3					1
Nov-02	50,724	4	8,098			28	41	3					1
Dec-02	51,523	4	8,337			26	42	3					1

Note:
Industrial customer counts from January 1998 through December 1999 overstate the total number of industrial customers as some customers received both sales and transportation services.

Question:

Provide the overall usage by rate classification, by month, from January 1997 through September 2006.

Response:

Please see the attached Schedule TRA DR 65 for the overall usage by rate class, by month, from January 1998 through September 2006.

The data regarding usage by rate class, by month, from January 1997 through December 1997 and for December 1998 are not readily available. The Company has requested retrieval of those records from the Company's off-site document storage service. Upon receipt, the Company will file an update to TRA DR 65.

CHATTANOOGA GAS COMPANY
CGC Schedule TRA DR 65
Usage by Customer Class by Month

	RESIDENTIAL	R-4 MULTI-FAMILY	COMMERCIAL	I1	T2	I1/T2	L1/T1	SS1	I1/T2 + T1	L1	T1	T3	SPECIAL CONTRACT
	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes	Volumes
Jan-98	652,498	5,372	627,148	52,181	169,736					26,930	686,648		
Feb-98	653,301	4,949	595,565	53,644	161,218					26,252	625,113		
Mar-98	523,183	4,670	504,069	71,877	152,200					254,905	981,950		
Apr-98	341,344	2,389	382,168	178,548	10,915					546,049	115,025		
May-98	156,557	1,677	214,445	66,409	105,060					137,511	504,590		
Jun-98	78,385	1,324	156,510	51,039	116,339					109,731	527,889		
Jul-98	67,740	1,322	140,045	153,568	19,088					487,907	121,632		
Aug-98	64,863	1,331	132,687	99,198	62,498					207,881	466,071		
Sep-98	68,188	1,263	145,267	47,145	118,132					44,208	558,660		
Oct-98	88,906	1,703	172,620	46,748	126,164					54,283	610,115		
Nov-98	258,732	3,170	239,603	34,767	114,200					54,996	641,014		
Dec-98													
Jan-99	767,295	5,448	691,682	44,060	131,622					49,229	707,854		
Feb-99	458,904	4,258	434,382	35,688	127,754					41,135	706,004		
Mar-99	579,797	4,023	542,746	37,151	153,148					37,450	825,663		
Apr-99	332,437	1,514	366,205	46,163	106,274					27,106	699,201		
May-99	129,294	1,246	169,048	140,135	527					611,397	95,340		
Jun-99	62,028	965	145,290	134,570	1,561					566,020	90,259		
Jul-99	72,514	1,007	140,117	94,510	41,600					285,228	339,826		
Aug-99	62,262	1,037	126,596	150,118	2,798					630,970	91,224		
Sep-99	77,771	977	143,757	145,666	2,078					590,918	85,007		
Oct-99	105,350	1,430	163,473	76,778	75,273					45,400	663,739		
Nov-99	260,206	1,574	242,773			131,896	627,587	57,098					64,430
Dec-99	452,062	1,430	387,112			144,670	665,924	0					62,204
Jan-00	654,569	7,525	561,289			133,731	665,554	43,035					63,345
Feb-00	766,607	3,730	657,594			130,611	659,866	53,582					59,587
Mar-00	415,024	2,321	448,586			147,234	681,008	68,453					68,416
Apr-00	297,804	1,982	300,849			127,990	619,912	74,598					62,916
May-00	176,800	1,024	227,261			113,856	591,345	93,911					66,514
Jun-00	89,967	927	178,945			119,273	551,219	82,094					53,591
Jul-00	68,860	881	115,480			111,316	426,569	122,677					60,175
Aug-00	58,023	908	128,491			117,946	552,728	117,888					65,358
Sep-00	77,294	926	153,618			111,692	535,753	14,924					63,239
Oct-00	127,130	1,475	178,524			119,674	618,165	136,713					0
Nov-00	228,512	2,830	213,308			142,719	550,794	137,041					0
Dec-00	686,857	4,439	545,945			159,594	380,015	24,938					0
Jan-01	992,773	5,819	847,449			184,020	363,639	11,008					317
Feb-01	721,395	3,080	794,372			162,575	522,855	1,843					11,399
Mar-01	498,898	3,045	466,666			169,329	554,026	119,669					52,833
Apr-01	424,426	1,662	419,693			144,361	452,426	108,692					19,752
May-01	139,621	669	215,157			145,905	453,963	111,821					56,123
Jun-01	84,747	1,031	154,539			159,569	436,818	106,507					58,680
Jul-01	74,302	1,043	151,522			148,992	421,392	104,060					52,016
Aug-01	66,794	980	133,921			162,764	441,069	112,631					43,339
Sep-01	76,947	1,104	130,698			143,855	510,512	0					50,573
Oct-01	118,657	1,577	165,197			165,460	593,171	0					50,516
Nov-01	266,363	1,927	245,829			150,740	433,096	107,558					48,831
Dec-01	339,105	9,951	307,952			159,036	474,177	46,357					51,692
Jan-02	755,363	3,477	569,434			163,834	513,760	84,701					46,703
Feb-02	591,351	3,517	556,084			153,000	471,163	72,867					43,328
Mar-02	590,595	2,575	544,458			161,620	469,678	97,042					48,271
Apr-02	316,993	1,296	357,571			144,094	426,737	69,516					44,233
May-02	147,730	1,102	198,749			146,770	448,434	75,120					52,131
Jun-02	99,803	927	167,607			142,427	410,725	109,817					54,878
Jul-02	71,633	772	131,469			122,265	398,853	108,068					58,506
Aug-02	60,653	731	124,209			121,233	421,425	103,176					60,275
Sep-02	64,514	675	137,064			144,493	404,509	85,048					64,579
Oct-02	83,132	811	153,170			152,187	428,915	77,454					83,436

CHATTANOOGA GAS COMPANY
CGC Schedule TRA DR 65
Usage by Customer Class by Month

	RESIDENTIAL	R-4 MULTI-FAMILY	COMMERCIAL	I1	T2	I1/T2	L1/T1	SS1	I1/T2 + T1	L1	T1	T3	SPECIAL CONTRACT
Nov-02	223,940	1,838	207,803			157,028	449,523	97,938					64,604
Dec-02	626,763	2,001	473,780			157,180	443,882	75,679					60,222
Jan-03	730,567	2,518	584,270			184,625	409,872	70,773					37,663
Feb-03	892,202	1,855	767,527			168,011	460,215	101,632					51,506
Mar-03	578,397	1,101	549,480			163,065	330,773	86,113					55,147
Apr-03	290,485	720	323,009			143,658	396,221	114,321					57,612
May-03	160,971	569	229,874			146,004	263,212	188,625					65,932
Jun-03	94,023	421	193,471			138,650	269,449	171,377					72,750
Jul-03	76,031	427	113,603			158,144	241,841	220,898					78,424
Aug-03	70,825	441	163,455			153,542	438,855	74,509					73,956
Sep-03	69,975	398	138,559			148,819	411,680	78,108					64,476
Oct-03	102,534	615	148,367			164,491	427,469	113,365					60,356
Nov-03	172,039	947	203,928			156,335	417,783	99,660					52,001
Dec-03	478,113	1,717	361,198			179,098	435,949	37,270					56,168
Jan-04	759,535	2,041	614,005			188,900	373,520	133,749					63,735
Feb-04	828,797	1,913	704,874			228,593	432,059	84,480					59,427
Mar-04	620,876	932	578,551			201,489	478,426	87,565					61,413
Apr-04	320,975	699	328,427			180,792	393,570	82,444					60,512
May-04	180,327	446	227,198			184,085	390,124	59,073					66,271
Jun-04	90,540	331	155,612			157,562	326,280	140,574					64,505
Jul-04	75,576	328	145,285			165,568	368,265	138,605					68,164
Aug-04	70,217	334	142,898			171,495	320,323	222,686					72,667
Sep-04	73,757	343	142,903			169,220	298,306	210,719					74,323
Oct-04	83,476	407	145,868			171,411	323,582	181,744					67,691
Nov-04	127,820	735	165,143			183,507	335,931	166,962					63,682
Dec-04	384,013	1,594	300,265			197,211	362,229	115,910					50,297
Jan-05	702,962	1,273	564,767			180,495		110,376	154,358	2,615	277,123	0	74,815
Feb-05	692,312	1,172	588,790			167,392		84,808	144,412	4,437	250,497	0	53,446
Mar-05	608,745	1,124	537,607			163,117		111,121	154,850	5,323	270,544	0	63,602
Apr-05	432,682	518	438,976			125,445		107,929	137,461	4,649	243,081	0	71,184
May-05	198,767	442	230,587			156,795		156,334	125,429	5,941	278,952	0	62,679
Jun-05	127,587	393	187,317			151,282		164,654	127,455	4,932	232,495	2,642	58,181
Jul-05	75,983	315	138,221			146,380		171,836	115,574	4,371	218,796	3,009	49,987
Aug-05	72,263	315	139,143			151,981		146,056	123,973	5,272	237,439	3,300	53,500
Sep-05	70,982	316	139,930			133,654		79,132	107,230	3,290	202,289	3,231	52,249
Oct-05	75,331	276	139,736			151,888		81,365	129,708	4,307	227,567	4,029	38,629
Nov-05	184,421	1,018	201,923			169,347		121,069	142,208	3,784	243,239	3,567	48,936
Dec-05	547,535	1,018	424,091			182,743		102,316	131,030	2,889	184,281	4,221	16,682
Jan-06	713,533	3,056	629,106			182,556		124,853	162,371	4,077	259,827	4,107	50,604
Feb-06	619,789	1,300	555,846			173,942		135,234	147,223	3,572	240,003	4,010	42,906
Mar-06	566,169	1,241	541,712			177,098		168,050	149,617	5,202	237,433	3,789	58,198
Apr-06	324,522	808	360,155			137,337		171,765	124,713	4,574	207,931	3,045	64,928
May-06	111,661	471	192,309			161,614		180,110	127,081	5,030	210,826	2,629	57,537
Jun-06	90,696	437	163,067			142,163		179,037	120,818	4,917	204,016	6,001	57,154
Jul-06	70,595	350	141,896			141,783		164,945	112,327	3,847	190,855	6,300	58,714
Aug-06	64,926	369	137,971			150,323		176,810	118,317	5,746	211,549	6,611	50,404
Sep-06	66,996	312	135,611			144,995		171,582	119,963	4,718	194,007	6,774	66,087

Question:

Are the sales figures reported in the Operating Revenue section of the monthly 3.03 reports the actual amounts billed to customers? Are the figures adjusted to include timing differences such as the current ACA balance? Provide a detailed explanation of the sales figures.

Response:

The volumes and revenues reported on the schedule titled "Monthly Schedule of Customers, Volumes, & Revenue" reflect the amount billed to the customers and does not reflect any timing differences. However based on this request item, there appears to be a misunderstanding of the methodology to account for recovery of gas cost through the PGA/ACA mechanism. Both the PGA billed and the resulting revenue are based on the estimated cost of gas. The gas cost recorded on CGC's books are based on the same estimated cost of gas. The difference in the cost of gas recovered through the PGA and the actual cost of gas is captured in the Deferred Gas Account. Here is an example of how the billing and accounting work.

A customer's total bill is based on the customer's usage and the total billing rate. (Base Rates plus PGA). The Gas Cost is the customer usage multiplied by the PGA Rate. Below is an example of the accounting process.

Assumption:

Customer usage	76 therms
PGA Rates	$1.00/therm
Actual Cost	$0.95/therm

As shown below the total amount billed to the customer is $105.84. This is composed of $29.84 base revenue and $76.00 PGA Revenue. The total revenue recorded on the books would be the $105.84. The amount recorded as Gas Cost is equal to the billed PGA Revenue $76.00. The Margin would be $29.84.

If the actual gas cost is $0.95/therm, the actual gas cost would be $72.20 (76/therms X $0.95/therm = $72.20.

The difference in the gas cost recorded on the Income Statement and the Actual Gas Cost is recorded as Deferred Gas Cost. (Actual Cost $72.20 – Gas Cost expensed $76.00=Deferred Gas Cost -$3.80).

Question:

Mr. Buckner recommends that the ALG depreciation rates adopted in Georgia be used in Tennessee. Please provide any analysis, regarding the comparability of assets, asset lives, etc. used in the Georgia depreciation study with those in Tennessee.

Response:

The Company is not aware of the existence of any such analysis that compares the assets, asset lives, etc. used in the Georgia depreciation study with those in Tennessee.

Question:

Please provide detailed specific dollar amounts for CGC's bare steel replacement program that are included in the projected 2007 attrition year CGC rate base on MJM-3, Schedule 1.

Response:

Please refer to Exhibit RRL-2 of the prefiled direct testimony of Richard Lonn. This exhibit includes the cost, accumulated depreciation reserve and accumulated deferred income taxes related to the bare steel cast iron program included in CGC's attrition year rate base.

Question:

Provide CGC's schedule, by year, and estimated dollar amount, for the current bare steel replacement program.

Response:

Based on current Company operations, the number of miles scheduled for replacement in a given year is defined during the prior year based on review of operating data such as main breaks and leak repairs. Currently the Company has proposed 10.76 miles of Bare Steel and Cast Iron replacement for 2007 with a total estimated annual expenditure of $3,952,803 (Installation and Removal) which is consistent with the Company's proposed eight year replacement program with a tracker. As stated above, mileages and costs for years 2008 and beyond have not been projected at this time other than for the Company's proposed PRP tracker.

Question:

Provide CGC's schedule, by year, and estimated dollar amount, for its proposed bare steel replacement program in this rate case.

Response:

Please see Exhibit RRl-1 from Richard Lonn's pre-filed direct testimony, which provides the estimated dollar amount by year for CGC's proposed PRP tracker.

Question:

Provide the amount of bare steel replacement, miles, and dollar amounts, for each of the past ten years.

Response:

Due to a change in accounting systems five years ago, the financial data for the bare steel/cast iron replacement projects is only currently available for the past four full years. This data is as follows:

Year	Amount
2002	$1,438,101
2003	$601,363
2004	$458,661
2005	$1,213,956

Concerning the miles of bare steel and cast iron main in Chattanooga Gas Company's system, the amounts identified in the system at the end of each year were as follows:

Year	Bare Steel/Cast Iron Main
1996	139 miles
1997	137 miles
1998	120 miles
1999	116 miles
2000	116 miles
2001	112 miles
2002	131 miles *
2003	95 miles *
2004	90 miles
2005	86 miles

* changes in mileage due to upgrades in mapping system in 2002 and addition of corrosion system information to the mapping system in 2003.

Chattanooga Gas Company
Docket Number 06-00175
TRA Staff -3
Data Request No. 72
11/13/2006

Question:

Provide actual Plant in Service and Accumulated Depreciation balances at 9/30/06 by account.

Response:

Please see attached schedules.

Chattanooga Gas

nmary of Plant, Property and Equipment September-06
Chattanooga Gas Company
GL8

G/L Account	FERC	Description	Ending Balance 9/30/2006
Intangible Plant			
300100	**301**	Organizational Expense	46,201
300200	**302**	Franchise & Consents	2,028
	Total	**Intangible Plant**	**48,229**
Storage Plant			
331040	**360**	Land	553,383
331150	**360**	Land Rights	-
331150	**361**	Structures & Improvements	11,704,939
331250	**362**	Gas Holders - LNG	4,515,240
331350	**363**	Purification Equipment	551,128
331450	**363.1**	Liquification Equipment	2,479,046
331550	**363.2**	Vaporizing Equiptment	2,387,568
331650	**363.3**	Compressor Equipment	37,726
331750	**363.4**	Measuring Equipment	95,050
331950	**363.5**	Other Equipment	865,245
	Total	**Storage Plant**	**23,189,326**
Distribution Plant			
351030	**374**	Land	35,553
351050	**374**	Land Rights	386,478
351100	**375**	Structures & Equipment	18,271
351200	**376**	Mains	80,143,124
351300	**377**	Compressor Station Equipment	1,613,696
351330	**378**	Measuring & Reg. Station Equip - General	212,328
351350	**379**	Measuring & Reg. Station Equip - City Gate	1,083,189
351400	**380**	Services	50,130,727
351500	**381**	Meters	6,877,203
351550	**381**	ERT's	-
351570	**381**	Metreteks	133
351600	**382**	Meter Installations	2,951,240
351700	**383**	House Regulators	3,007,803
351800	**384**	House Regulator Installations	170,542
351850	**385**	Industrial Meas & Reg Station Equipmnt	220,719
351900	**387**	Other Distribution Equipment	141,330
351950	**386**	Other Property on Customer's Premises	19,246
	Total	**Distribution Plant**	**147,011,582**
General Plant			
361030	**389**	Land	-
361100	**390**	Structures & Improvements	91,435
361200	**391**	Office Furniture	13,607
361250	**391**	Data Processing Equipment	1,506,614
361300	**392**	Transportation Equipment	378,079
361400	**393**	Stores Equipment	71,130
361500	**394**	Tools, Shop & Garage Equipment	359,595
361600	**395**	Laboratory Equipment	21,879
361700	**396**	Power-Operated Equipment	48,044
361800	**397**	Communication Equipment	-
361900	**398**	Miscellaneous Equipment	11,511
352CI	**CIAC**	Contribution in Aid of Construction	(855,736)
	Total	**General Plant**	**1,646,157**
		Total (all Plant)	**171,895,294**
		Total General Ledger	**171,926,682**
		Variance	**(31,387)**

Chattanooga Gas

Accumulated Depreciation Roll-forward
Chattanooga Gas Company
GL8

September-06

G/L Account	FERC	Description	Ending Balance 9/30/2006
Storage Plant			
331150	**361**	Structures & Improvements	(1,161,129)
331200	**362**	Gas Holders - Natural	(4,310)
331250	**362**	Gas Holders - LNG	(4,371,060)
331350	**363**	Purification Equipment	(337,010)
331450	**363.1**	Liquification Equipment	(1,489,256)
331550	**363.2**	Vaporizing Equiptment	(1,087,092)
33165	**363.3**	Compressor Equipment-LNG	(252)
331750	**363.4**	Measuring Equipment	(83,952)
331950	**363.5**	Other Equipment	(721,598)
			(9,255,660)
Distribution Plant			
351050	**374**	Land Rights	(90,849)
351100	**375**	Structures & Equipment	(11,143)
351200	**376**	Mains	(39,396,384)
351300	**377**	Compressor Station Equipment	(1,361,665)
351330	**378**	Measuring & Reg. Station Equip - General	(53,893)
351350	**379**	Measuring & Reg. Station Equip - City Gate	(467,957)
351400	**380**	Services	(19,972,620)
351500	**381**	Meters	(3,529,967)
351550	**381**	ERT's	(37,853)
351570	**381**	Metreteks	(22)
351600	**382**	Meter Installations	(916,620)
351700	**383**	House Regulators	(1,261,999)
351800	**384**	House Regulator Installations	(63,954)
351850	**385**	Industrial Meas & Reg Station Equipmnt	(111,142)
351900	**387**	Other Distribution Equipment	(49,955)
351950	**386**	Other Property on Customer's Premises	(9,296)
			(67,335,320)
General Plant			
361030	**389**	Land	(143)
361100	**390**	Structures & Improvements	(12,733)
361200	**391**	Office Furniture	(3,516)
361250	**391**	Data Processing Equipment	(1,051,611)
361300	**392**	Transportation Equipment	(467,107)
361400	**393**	Stores Equipment	(94,762)
361500	**394**	Tools, Shop & Garage Equipment	(285,086)
361600	**395**	Laboratory Equipment	(28,220)
361700	**396**	Power-Operated Equipment	(85,449)
361800	**397**	Communication Equipment	9,785
361900	**398**	Miscellaneous Equipment	(14,096)
			(2,032,937)
		Total (all Plant)	**(78,623,917)**
		Total GL - Accts 100200 &100210	**(60,953,261)**
		Total GL - Acct 248305 (ARO)	**(17,662,177)**
		Total Per General Ledger	**(78,615,438)**
		Variance	**(8,479)**

(61,199,658)

Chattanooga Gas Company
Docket Number 06-00175
TRA Staff -3
Data Request No. 73
11/13/2006

Question:

Provide updated 13 month average balances for all rate base items as of 9/30/06.

Response:

Please see attached schedule.

	Average For 12 MTD
Additions	
Utility Plant	$ 165,523,294
Construction Work In Progress	6,351,120
Property Held for Future Use	
Materials & Supplies & Gas Stored	23,992,418
Other Additions(Itemized)	
Working Capital	2,045,661
AGSC Net Plant as Filed in Docket 06-00175 - (Includes Cost, A/D and ADIT)	1,900,241
Total Additions.	$ 199,812,734
Deductions	
Accumulated Depreciation	$ (75,173,690)
Accumulated Deferred Income Tax	(15,925,562)
Unamortized Investment Credit-Pre 1971	
Customer Deposits	(1,793,580)
Other Deductions (Itemize)	-
Contribution In Aid Of Construction	(1,774,959.72)
Customer Advances For Construction	(286,394)
Accrued Interest On Customer Deposits	(792,095)
Total Deductions	$ (95,746,281)
Rate Base	$ 104,066,454

Question:

Please submit cost of service studies for the 12 months ended December 31, 2005 and December 31, 2006.

Response:

Please see attached schedules.

Question:

Please submit a cost of service study with interruptible customers receiving allocations based on them being classified as firm customers, for the 12 months ended December 31, 2005, December 31, 2006 and December 31, 2007.

Response:

Please see attached schedules.

Question:

When calculating reserve margin, how is interruptible demand counted in the calculation of peak day demand?

Response:

When calculating peak day demand requirements, interruptible usage is not included. Due to its nature, interruptible usage is curtailed on a peak, or design day. The system's peak day requirements include only usage for firm customers. The only usage for interruptible customers that would be considered in calculating peak day demand is the portion of their usage that the customer has contracted to be delivered on a firm basis, for which the customer pays a demand charge.

Question:

What cost savings or system benefits are realized by curtailing interruptible customers when operational or pressure problems arise?

Response:

There are many benefits to curtailing customers when CGC experiences operational or pressure problems. From a fundamental rate design perspective, the system is not designed to serve interruptible customers and firm customers on the peak coldest days of the year. When CGC experiences delivery constraints, interruptible customers are expected to curtail their usage so CGC can maintain service to firm customers. Therefore, CGC does not have to install additional capacity to maintain service to them 365 days per year and interruptible customers benefit from paying a lower rate year round.

Operationally, there may be instances where CGC's distribution system or portions of the system cannot physically deliver the volumes of gas that both firm and interruptible customers may try to use on a peak day. On those days, the pressure could drop to the point where residential customers losing service entirely. This would have a major impact because service cannot be restored by simply increasing the pressure again. CGC personnel would have to visit each premise to restore service and re-light pilots. CGC monitors system pressures and will issue a curtailment order to interruptible customers in the affected area to avoid such a situation.

Interruptible customers may also be curtailed for other operational reasons such as to preserve LNG inventory during a long cold winter, preserve interstate storage during periods of high market prices, emergencies, etc. Under certain circumstances, CGC may even curtail interruptible customers to more cost effectively or safely perform maintenance on the distribution system.

Question:

How many firm customers have switched to the interruptible class each year since January 2000? How long were these customers served as firm customers?

Response:

According to the Company's records, no firm customers have switched to the interruptible class since January 2000.

Question:

How many interruptible customers have never received firm service?

Response:

Chattanooga Gas Company has been part of the AGL family in 1988. Many of the interruptible customers were added to the system prior to 1988 and the Company does not have records for all interruptible customers since they became active on the system. As stated in the Company's response to TRA DR 78, no interruptible customers currently on the system have received firm service since 2000.

Typically, an interruptible customer is a very large customer that builds their facilities with the intention of receiving interruptible service. Through this anecdotal evidence and the fact that no interruptible customer has received firm service since 2000, the Company would speculate that the majority of the interruptible customers have never received service under a firm tariff.

Question:

Have CGC's storage assets ever been used to supply interruptible customers if the customer's marketer failed to deliver gas to the citygate?

Response:

Yes. CGC uses its storage assets to balance interruptible customers on a daily basis and on curtailment days when their marketer fails to deliver. On any day when a marketer fails to deliver the full amount of gas used by a customer to the city-gate, the Company utilizes its storage assets to provide the difference between the customer's actual consumption and its marketer's under delivery. Likewise, if a marketer delivers more gas than a customer can consume the Company cuts back on its deliveries from storage for the day to its firm sales customers. This is what is meant by balancing. If an interruptible customer's usage for the month exceeds the amount of gas that the customer's marketer delivers to the city-gate, the cash-out provision of the tariff applies and the customer pays a premium for the gas if the usages is more than 10% greater than the amount delivered. If the customer uses more gas than the customer's marketer delivers on a curtailment day, the penalty provision of the tariff applies. In both instances the premium and the penalties collected from the interruptible customer are credited to the deferred gas account and used to reduce the cost billed to firm customers. The graduated cash-out provision and penalty provision are designed to encourage interruptible customers to have the appropriate amount of gas delivered in order to protect the interruptible customer and to compensate the firm customers for such usage.

Question:

Provide the monthly billing demands that correspond to the customer usage submitted in TRA FG 30.

Response:

Please see the attached Schedule TRA DR 81 for the monthly billing demands that correspond to the customer usage submitted in TRA FG 30.

CHATTANOOGA GAS COMPANY
Schedule TRA DR 81 - Update of FG 30 - Twenty-five Largest Customers
(Based on Volumes Delivered from January 2005 through December 2005)

Volumes In Dths

	Account #	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
1	28-9-09500	69,602	63,316	67,082	65,360	63,672	62,070	59,778	60,581	53,997	69,797	59,724	43,451	738,428
2	28-9-19800	67,914	61,933	48,620	30,034	64,376	61,491	63,579	69,249	54,195	58,072	64,319	66,034	709,815
3	28-9-00650	74,815	53,446	63,602	71,184	62,679	58,181	49,967	53,500	52,249	38,629	48,936	16,682	643,871
4	28-9-06200	24,666	35,856	39,010	24,389	48,419	47,801	45,559	50,425	35,207	40,055	49,141	46,516	487,042
5	28-9-06450	39,621	37,403	40,316	38,482	39,134	35,375	36,743	38,121	30,163	40,010	36,886	23,978	436,228
6	28-9-01950	11,531	11,795	13,330	30,329	63,259	40,883	56,439	37,006	76	95	31,800	31,124	327,666
7	60-1-01200	32,201	30,095	32,017	24,550	25,194	24,661	20,031	30,924	27,182	10,558	35,144	20,264	312,819
8	28-9-20540	30,085	28,823	29,988	25,351	23,639	22,374	21,395	21,274	20,258	26,317	27,684	25,969	303,136
9	28-9-19050	21,603	6,579	26,376	29,647	32,408	31,428	27,532	21,370	21,031	30,025	30,169	17,260	295,426
10	60-1-03100	20,812	20,947	21,667	22,468	22,135	23,652	23,010	23,785	21,971	23,006	20,787	8,261	252,498
11	28-9-16500	22,516	16,921	19,626	17,548	20,133	19,403	17,636	19,699	12,934	20,390	18,530	14,795	220,131
12	28-9-16650	14,615	11,816	17,673	17,855	17,633	15,399	17,240	18,459	16,613	16,149	14,906	13,943	192,502
13	28-9-12300	16,660	107	17,751	10,841		31,579	31,707	26,028	13,971	87	116	42	148,869
14	28-9-16100	14,263	13,496	14,509	12,195	13,120	11,765	10,807	12,169	9,776	10,056	11,890	10,968	145,014
15	28-9-13600	13,400	13,551	14,654	12,723	12,248	12,964	10,600	11,229	8,847	11,123	9,843	7,375	138,557
16	28-9-04600	15,773	16,462	16,192	7,436	6,408	6,303	7,437	6,247	7,201	7,517	14,678	20,694	134,368
17	28-9-18200	13,993	12,249	14,048	11,623	9,760	9,545	9,219	9,414	7,838	10,186	11,871	12,538	132,293
18	28-9-20300	15,620	13,779	13,307	8,309	8,618	12,050	12,274	4,778	6,860	9,603	10,187	11,953	127,338
19	28-9-03950	18,949	16,415	15,987	9,902	8,369	6,123	7,563	5,110	5,656	7,602	10,239	13,899	125,813
20	28-9-16700	9,933	8,428	9,534	11,369	11,060	10,656	10,074	10,621	7,142	10,189	10,530	5,081	114,815
21	60-1-02070	9,198	8,163	8,835	7,759	7,821	9,508	8,823	10,064	7,568	12,013	11,155	8,774	109,680
22	28-9-16550	10,494	9,559	9,818	9,169	5,460	9,573	7,746	10,184	6,923	8,309	7,963	3,397	98,593
23	60-1-02050	8,965	7,782	9,638	8,640	6,254	9,072	5,203	7,948	6,934	8,874	8,974	6,561	96,844
24	28-9-17000	7,698	8,624	8,832	9,490	8,307	9,133	7,367	6,338	6,015	5,697	8,386	5,884	89,771
25	28-9-01100	6,792	8,331	8,441	7,238	7,276	6,705	4,911	5,310	5,776	7,501	9,798	10,477	86,556

Demand Units

	Account #	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
1	28-9-09500	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	28-9-19800	2,356	2,356	2,356	2,356	2,356	2,354	2,354	2,354	2,354	2,354	2,350	2,350
3	28-9-00650	10	10	10	10	10	10	10	10	10	10	10	10
4	28-9-06200	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	28-9-06450	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6	28-9-01950	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7	60-1-01200	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8	28-9-20540	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	700	700	700
9	28-9-19050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	60-1-03100	300	300	300	300	300	300	300	300	300	300	300	300
11	28-9-16500	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	28-9-16650	860	860	860	860	860	860	860	860	660	860	860	877
13	28-9-12300	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
14	28-9-16100	250	250	250	250	250	100	100	100	100	100	100	100
15	28-9-13600	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	28-9-04600	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	700	700
17	28-9-18200	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
18	28-9-20300	662	662	662	662	862	861	661	661	861	661	661	661
19	28-9-03950	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	28-9-16700	20	20	20	20	20	21	21	21	21	21	21	21
21	60-1-02070	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	28-9-16550	n/a	n/a	n/a	n/a	n/a	80	80	80	80	80	80	80
23	60-1-02050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	300	300	300
24	28-9-17000	580	580	580	580	580	581	581	581	581	581	581	533
25	28-9-01100	401	401	421	421	421	420	420	420	420	420	547	547

Question 82: Define load factor.

Response:

Load factor is the ratio of the average daily load to design day load. Load factor is calculated by the following formula:

LOAD FACTOR = ANNUAL LOAD/ (DESIGN DAY LOAD*365)

Load factor is a proxy measure of annual average system capacity utilization, since the system capacity is based upon the design day load with a reserve margin.

Question 83: Explain the benefits to the CGC system provided by high load factor consumption. Also, please describe the effect of low load factor customers on the system.

Response:

Load factor is a proxy measure of annual average system capacity utilization, since the system capacity is based upon the design day load with a reserve margin. Therefore, the higher the load factor the more efficiently the system's capacity is utilized. With higher load factors comes cost savings from more efficient capacity utilization and cheaper gas supply by being able to use lower cost flowing base load gas than higher priced peaking and storage gas. These cost savings directly benefit both the company and customers. Lower load factor customers lead to less efficient use of the system's capacity and greater use of higher cost storage and peaking assets to meet design day loads.

Question:

The definition of Billing Demand for Medium Commercial and Industrial General Service as compared to the definition of Billing Demand for Commercial and Industrial Large Volume Firm Sales Service indicates that Medium C&I users do not have meters capable of recording the maximum daily usage for a month. If this is the case, could meters be reprogrammed to record this information or would the meters have to be replaced? What would the new meter cost? If this is not the case, why are the definitions different?

Response:

It is correct that the definition of billing demand for our proposed C-2 rate class is different than is for our existing industrial classes due to the fact that the meters for the proposed C-2 class are not read daily, but instead on a monthly basis.

In order to obtain daily usage information from these firm customers, it would be necessary to install additional metering equipment to the customer's existing meter. Typically the Company only installs daily reading equipment, such as Metretek, for large industrial customers and not firm customers due to the expense of the equipment, installation, phone line service, system changes, and on-going maintenance costs associated with the equipment. As an example, some of the costs associated with installing Metretek are listed below:

1. Electronic Corrector - $1000
2. Metretek IMU - $700 (land-line) or IMU Cellular - $900 (which one is used is based on meter set location)
3. Customer would have to provide phone line or cell service
4. Customer would have to supply electrical power
5. Approximately $500 labor and miscellaneous supplies to install
6. System programming changes to separate firm reads from interruptible customer readings from the Company's Gas Operating System (GOS)
7. On-going O&M cost to units for repair and maintenance when the unit fails to report daily information

Question 85: Has CGC considered a block rate dependent on peak usage (similar to hours use of demand rates used by electric utilities) for medium C&I customers rather than the proposed structure? If CGC has considered such a block rate why did they elect not to use it?

Response:

No, we did not consider it because natural gas demand billed hourly is not a feasible solution, considering that there is a complete lack of historical data for the customers. Daily meters would cost approximately $2400 per customer, not including other accoutrements a customer would need (phone line, electrical power) and other costs to the Company (upgrading the Gas Operating System and ongoing O&M). It would be impossible to calculate the cost of hourly metering as it would require even further changes to the gas operating system, billing system, and etcetera.

In addition, gas is not sold at an hourly rate on the interstate market. Gas is currently scheduled and sold daily. The ability to be able to buy gas at an hourly rate is not feasible, due to outside physical constraints as well.

We are proposing a peak charge to the customers which is, for the natural gas industry, the closest approximation to how electric utilities calculate demand rates.

Question:

Provide a schedule for the last five years, by month, showing all curtailments to interruptible customers.

Response:

See attached.

Effective Date - Start of Gas Day	Termination Date - Start of Gas Day	Number of Days
01/08/01	01/10/01	2
01/13/01	02/01/01	18
12/26/01	12/27/01	1
01/02/02	01/05/02	3
01/07/02	01/08/02	1
02/05/02	02/07/02	2
12/05/02	12/06/02	1
01/11/03	01/14/03	3
01/17/03	01/19/03	2
01/22/03	01/28/03	6
02/26/03	03/11/03	13
12/16/03	12/23/03	7
01/07/04	01/11/04	4
01/19/04	01/23/04	4
10/16/04	10/17/06	1
10/26/04	10/29/04	3
12/13/04	12/21/04	8
01/01/05	01/02/05	1
01/17/05	01/19/05	2
01/23/05	01/24/05	1
09/23/05	09/28/05	5
12/05/05	12/10/05	5