Appendix C

Electric and Natural Gas Load Forecasts

The current electric and natural gas forecast reports, as required by 199 IAC 35.9(1) and 35.10(1), are included in this Appendix.

C.1 – (Confidential) IPL Electric Forecast (199 IAC 35.9(1))

This section of Appendix C is the electric forecast.

C.2 – (Confidential) IPL Natural Gas Forecast (199 IAC 35.10(1))

This section of Appendix C is the natural gas forecast.

APPENDIX C.1

Interstate Power and Light Company

Electric Forecasts

November 30, 2012

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Reference: 199 IAC 35.11

Additional Filing Requirements. In those years an electric utility does not file an energy efficiency plan, the utility shall file by May 15 the information required in subrules 35.9(1) and 35.9(2). If there has been no change in the utility's forecast procedure in regard to information required in paragraphs 35.9(1) "d" through "f," the utility may state "no change from previous forecast" for each paragraph….

The current IPL electric load forecast was updated in May 2012. For ease of reference, the section numbering below is the same as the numbering used in Appendix E1 of IPL's Application in Docket No. EEP-08-1 filed April 23, 2008.

2. ELECTRIC LOAD FORECASTS

2.1.1 Electric Summer Demand

Reference: 199 IAC 35.9(1)

Load forecast. Information specifying forecasted demand and energy use on a calendar year basis which shall include:

a. A statement, in numerical terms, of the utility's current 20-year forecasts including reserve margin for summer and winter peak demand and for annual energy requirements. The forecast shall not include the effects of the proposed programs in subrule 35.8(8), but shall include the effects to date of current ongoing utility energy efficiency programs….

Table 2.1.1 contains the 20-year forecast of summer demand, including reserve margin. Included for consistency is the five-year history. This forecast was developed in May 2012.

Table 2.1.1
Electric Summer Demand, including Reserve Margin (MW)

Year	Summer Firm Peak Demand	Diversity	Adjusted Net Internal Demand	Planning Reserve Margin*	Summer Firm Demand plus Reserves
2007	2,813	NA	2,813	506	3,319
2008	2,732	NA	2,732	492	3,224
2009	2,700	NA	2,700	145	2,845
2010	2,670	NA	2,670	120	2,790
2011	2,923	NA	2,923	111	3,034
2012	2,778	17	2,761	105	2,865
2013	2,779	17	2,762	105	2,867
2014	2,719	16	2,703	102	2,805
2015	2,755	17	2,739	104	2,843
2016	2,791	17	2,774	105	2,879
2017	2,825	17	2,808	106	2,914
2018	2,857	17	2,840	108	2,948
2019	2,885	17	2,868	109	2,976
2020	2,918	18	2,900	110	3,010
2021	2,945	18	2,928	111	3,039
2022	2,973	18	2,955	112	3,067
2023	3,004	18	2,986	113	3,099
2024	3,038	18	3,020	115	3,135
2025	3,071	18	3,052	116	3,168
2026	3,100	19	3,082	117	3,199
2027	3,129	19	3,110	118	3,228
2028	3,158	19	3,139	119	3,258
2029	3,189	19	3,170	120	3,290
2030	3,222	19	3,203	121	3,324
2031	3,255	20	3,235	123	3,358

* The reserve margin is assumed to be 3.79 percent in 2012-2031 based on the MISO 2012/2013 planning reserve margin, which also considers demand diversity within MISO and the conversion to a UCAP system from an ICAP. In 2009, the MISO planning reserve margin was 5.35 percent while in 2010 and 2011, it was 4.5 percent and 3.8 percent respectively. Prior to 2009, the planning reserve margin was 18 percent, based on a different form of

calculation. Note that for this table the historical reserve margin in this column is the ex ante planning reserve margin and not actual realized reserve margin. In future filings, IPL intends to follow MISO's enhanced resource adequacy construct which, among other changes, is based on annual, and not seasonal, demand requirements.

2.1.2 Electric Winter Demand

Table 2.1.2 contains the 20-year forecast of winter demand, including reserve margin.

Included for consistency is the five year history.

Table 2.1.2
Electric Winter Demand, including Reserve Margin (MW)

Year	Winter Demand	Planning Reserve Margin*	Winter Demand + Reserves
2007	2,439	439	2,878
2008	2,458	442	2,900
2009	2,435	130	2,565
2010	2,524	114	2,638
2011	2,454	93	2,547
2012	2,561	97	2,658
2013	2,563	97	2,660
2014	2,515	95	2,610
2015	2,548	97	2,644
2016	2,580	98	2,678
2017	2,610	99	2,709
2018	2,640	100	2,740
2019	2,667	101	2,768
2020	2,696	102	2,798
2021	2,722	103	2,825
2022	2,747	104	2,851
2023	2,776	105	2,881
2024	2,807	106	2,914
2025	2,837	108	2,945
2026	2,865	109	2,974
2027	2,892	110	3,001
2028	2,918	111	3,028
2029	2,948	112	3,059
2030	2,977	113	3,090
2031	3,008	114	3,122

* See footnote on page 2-1

2.1.3 Annual Energy

Table 2.1.3 contains the 20-year forecast of annual energy. Included for consistency is the five-year history, not weather-normalized. The forecast reported in Table 2.1.3 was last modified in May 2012.

Table 2.1.3
Electric Annual Energy (GWH)

Year	Energy
2007	17,574
2008	17,680
2009	15,847
2010	16,177
2011	16,757
2012	16,612
2013	16,702
2014	16,415
2015	16,554
2016	16,715
2017	16,897
2018	17,056
2019	17,235
2020	17,405
2021	17,572
2022	17,719
2023	17,883
2024	18,068
2025	18,258
2026	18,430
2027	18,614
2028	18,816
2029	19,027
2030	19,255
2031	19,486

2.1.4 Five Year Historical Peak Demand

Reference: 199 IAC 35.9(1)

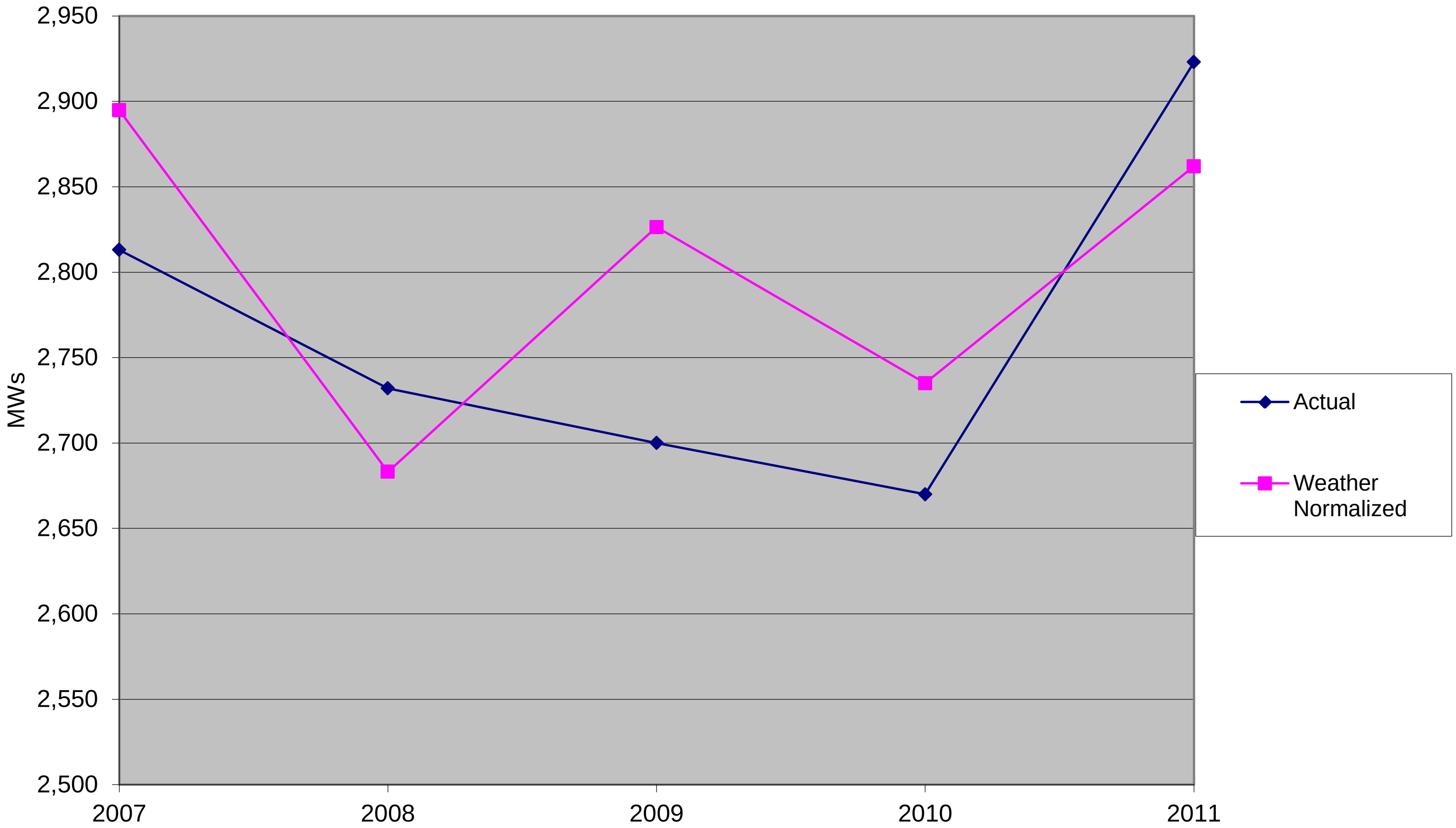
> ***b. The date and amount of the utility's highest peak demand within the past five years, stated on both an actual and weather-normalized basis. The utility shall include an explanation of the weather-normalization procedure.***

IPL's highest firm peak demand was 2,923 MW on 8/2/2011 at 17:00 on a non-weather normalized basis. On a weather normalized basis, the highest firm peak amount was 2,895 MW on 8/28/2007 at 17:00. The weather coefficient from the demand forecast model is used to weather normalize summer firm peak. The difference between actual and normal weather is multiplied by the weather coefficient to get the change in the peak due to weather which is then added to the firm peak. Table 2.1.4 gives Interstate Power and Light's actual and weather-normalized firm peaks for the last five years. Figure 2.1.4 gives a graphical representation of these data.

Table 2.1.4
Actual and Weather-Normalized Firm Peaks (MWs)

Year	Actual	Weather-Normalized
2007	2,813	2,895
2008	2,732	2,683
2009	2,700	2,826
2010	2,670	2,735
2011	2,923	2,862

Figure 2.1.4
Actual and Weather Normalized Firm Peaks



2.1.5 Forecast Comparisons

Reference: 199 IAC 35.9(1)

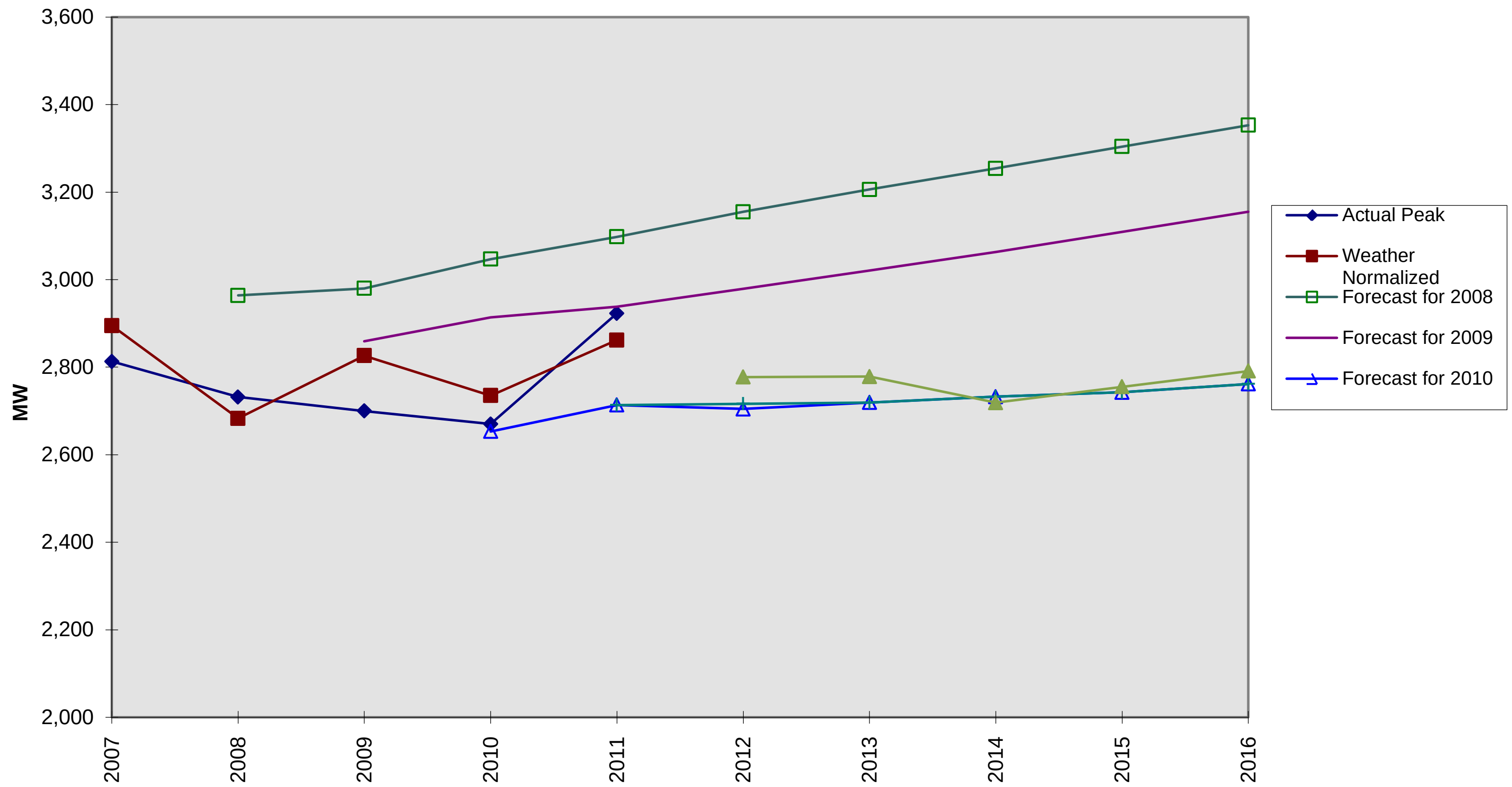
> ***c. A comparison of the forecasts made for each of the previous five years to the actual and weather-normalized demand in each of the previous five years.***

Table 2.1.5 contains the historical actual and weather-normalized annual firm peaks as well as the forecast firm peaks for the 2008 through 2012 forecasts. Figure 2.1.5 presents a graphical representation of these firm peaks. Note that the WN (weather-normalized) firm peak assumes normal peaking weather at the time of summer peak.

Table 2.1.5
Forecast Comparisons
Summer Firm Peaks (MWs)

			Forecast made for				
Year	Actual	WN	2012	2011	2010	2009	2008
2007	2,813	2,895					
2008	2,732	2,683					2,964
2009	2,700	2,826				2,859	2,980
2010	2,670	2,735			2,653	2,914	3,047
2011	2,923	2,862		2,713	2,713	2,938	3,098
2012			2,778	2,716	2,704	2,979	3,155
2013			2,779	2,719	2,719	3,021	3,206
2014			2,719	2,732	2,732	3,063	3,254
2015			2,755	2,742	2,742	3,109	3,304
2016			2,791	2,762	2,762	3,155	3,353
2017			2,825	2,783	2,783	3,201	3,403

Figure 2.1.5
Summer Firm Peak Forecast Comparison



<u>2.1.6 Methods and Assumptions</u>

Reference: 199 IAC 35.9(1)

> ***d. An explanation of all significant methods and data used, as well as assumptions made, in the current 20-year forecast. The utility shall file all forecasts of variables used in its demand and energy forecasts and shall separately identify all sources of variable inputs used….***

Energy Forecast

IPL's energy forecast is based on class level regression models for the long- and short-term adjusted for consistency with recent trends, as well as estimates of Other sales, Large Industrial sales, and losses. The statistical models were created in July 2011, with the forecast updated in May 2012. DSM is included implicitly in the forecast by inclusion in the historical loads used to develop forecasted sales.

2.1.6.1 Short-Term Residential Energy

The short-term Residential sales are modeled using billing month observations of residential use per customer sales. The variables used and their descriptions are as follows:

<u>Actual Residential HDD (wgtHDD):</u> The sales weighted average of the route level base 65 HDD for the billing month.

<u>Actual Residential Cooling Degree Days (wgtCDD):</u> The sales weighted average of the route level base 65 CDD for billing month.

<u>IA Real Personal Income (IA_RPI_M):</u> Monthly observations of IA real personal income.

Common Residential Definition (ComDef): An indicator variable for January 2005 and beyond. This variable is necessary due to an increase in the number of customers in the residential class resulting from an internal inquiry into the definition of a residential customer.

Monthly Indicators (Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec): Variables that take the value of one (1) during the designated month to indicate systematic fluctuation in sales not related to the weather or economy and zero (0) otherwise.

The model equation is as follows:

(Residential kWh/customer) =340.145+ 0.265*(wgtHDD) +1.498*(wgtCDD) + .003*(IA_RPI_M) – 20.575*(ComDef) –104.710*(Feb) -127.541*(Mar) -129.980*(Apr) -128.254*(May) -87.386*(Jun) -19.166*(Jul) +4.114*(Aug) -17.969*(Sep)-79.273*(Oct)-79.848*(Nov)-19.402*(Dec) + e

where e is an error term.

The model parameters are as follows:

Table 2.1.6a
Short-Term IPL Residential Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	340.145	6.20	0%
wgtHDD	0.265	14.21	0%
wgtCDD	1.498	23.56	0%
IA_RPI_M	0.003	4.82	0%
ComDef	-20.575	-3.03	0%
Feb	-104.710	-11.66	0%
Mar	-127.541	-11.98	0%
Apr	-129.980	-7.71	0%
May	-128.254	-5.83	0%
Jun	-87.386	-3.33	0%
Jul	-19.166	-0.64	53%
Aug	4.114	0.13	89%
Sep	-17.969	-0.63	53%
Oct	-79.273	-3.25	0%
Nov	-79.848	-4.27	0%
Dec	-19.402	-1.72	9%
R^2=0.9804 Adj. R^2=0.9777			

Growth rate forecast assumptions for Customers are shown in Table 2.1.6b, Short-Term IPL Residential Sales Model Assumed Growth Rates. Forecasts of the independent variables are based on:

- Customer Forecasts are based on recent historical annual increases;
- IA Real Personal Income is based on a IHS Global Insight forecast; and
- The weather variables are the average weather from 1991-2010.

Table 2.1.6b
Short-Term IPL Residential Sales Model Assumed Growth Rates
(Filed Confidentially)

	IA RPI (% change quarterly)				**Customers**
Year	**Q1**	**Q2**	**Q3**	**Q4**	**(Annual)**
2011					
2012					
2013					

2.1.6.2 Short-Term Commercial Energy

The short-term Commercial sales are modeled using billing month observations of commercial use per customer sales. The variables used and their descriptions are as follows.

Actual Commercial Heating Degree Days (wgtHDD): The sales weighted average of the route level HDD for the billing month.

Actual Commercial Cooling Degree Days (wgtCDD): The sales weighted average of the route level CDD for the billing month.

IA Real Personal Income (IA_RPI_M): Monthly observations of IA real personal income.

Monthly Indicators (Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec): Variables that take the value of one (1) during the designated month to indicate systematic fluctuation in sales not related to the weather or economy and zero (0) otherwise.

The model equation is as follows:

(Commercial kWh/customer) = 1277.690+ 0.491*(wgtHDD) + 3.185*(wgtCDD) + 0.023*(IA_RPI_M) -274.255*(Feb) -396.731*(Mar) -355.557*(Apr) -248.490*(May) - 26.192*(Jun) + 51.117*(Jul)+ 78.472*(Aug) + 236.747*(Sep) + 103.358*(Oct) - 16.369*(Nov)+ 135.374*(Dec) + e

where e is an error term.

The model parameters are as follows:

Table 2.1.6c
Short-Term IPL Commercial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	1277.690	6.77	0%
wgtHDD	0.491	5.32	0%
wgtCDD	3.185	10.10	0%
IA_RPI_M	0.023	14.55	0%
Feb	-274.255	-6.17	0%
Mar	-396.731	-7.30	0%
Apr	-355.557	-4.18	0%
May	-248.490	-2.26	3%
Jun	-26.192	-0.20	84%
Jul	51.117	0.35	73%
Aug	78.472	0.52	61%
Sep	236.747	1.70	9%
Oct	103.358	0.87	39%
Nov	-16.369	-0.18	86%
Dec	135.374	2.44	2%
R^2=0. 0.9231 Adj. R^2= 0.9134			

Growth rate forecast assumptions for commercial customers, and economic growth are shown in Table 2.1.6d, Short-Term IPL Commercial Sales Model Assumed Growth Rates. Forecasts of the independent variables are based on:

- Customer Forecasts are based on recent historical annual increases;
- IA Real Personal Income is based on a IHS Global Insight forecast; and
- The weather variables are the average weather from 1991-2010

Table 2.1.6d
Short-Term IPL Commercial Sales Model Assumed Growth Rates
(Filed Confidentially)

Year	IA RPI (% change quarterly) Q1	Q2	Q3	Q4	Customers (Annual)
2011					
2012					
2013					

2.1.6.3 Short-Term Industrial Energy

The short-term Industrial sales are modeled using billing month observations of use per customer for the Industrial class. The variables used and their descriptions are as follows:

Actual Industrial Cooling Degree Days (wgtCDD): The sales weighted average of the route level CDD for the billing month.

Industrial Definition (IndDef): An indicator variable that takes the value of one (1) for the period from December 2004 onward based on an increase in the number of customers following an analysis on the definition of an industrial customer and zero (0) otherwise.

IPL Indicator (IPL): An indicator that use per customer is influenced by the merger that created the IPL system that takes the value of one (1) and zero (0) otherwise.

Monthly Indicator (Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec): A variable that takes the value of one (1) during the designated month to indicate systematic fluctuation in sales not related to the weather or economy.

The model equation is as follows:

(Industrial kWh/customer) = 176,239 + 92.646*(wgtCDD) -2,869.761*(IPL) - 22,593*(IndDef) -3,413.091*(Feb) -3,883.445*(Mar) -8,282.719*(Apr) -5,023.580*(May)

-7,085.287*(Jun) -10,859 *(Jul) -7,172.199*(Aug) + 862.103*(Sep) + 2,675.790*(Oct) - 1,135.270*(Nov)+ 4,994.614*(Dec) + e

where e is an error term.

The model parameters are as follows:

Table 2.1.6e
Short-Term IPL Industrial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	176,239	69.38	0%
wgtCDD	92.646	4.49	0%
IPL	-2,869.761	-1.37	17%
INDDef	-22,593	-13.42	0%
Feb	-3,413.091	-1.11	27%
Mar	-3,883.445	-1.27	21%
Apr	-8,282.719	-2.71	1%
May	-5,023.580	-1.61	11%
Jun	-7,085.287	-1.74	8%
Jul	-10,859	-1.95	5%
Aug	-7,172.199	-1.26	21%
Sep	862.103	0.22	83%
Oct	2,675.790	0.84	40%
Nov	-1,135.270	-0.36	72%
Dec	4,994.614	1.59	11%
R^2=0.806 Adj. R^2=0.782			

Growth rate forecast assumptions for Customers are shown in Table 2.1.6f, Short-Term IPL Industrial Sales Model Assumed Growth Rates. Forecasts of the independent variables are based on:

- Customer Forecasts are based on recent historical annual increases; and
- The weather variables are the average weather from 1991-2010

Table 2.1.6f
Short-Term IPL Industrial Sales Model Assumed Growth Rates
(Filed Confidentially)

Year	Customers
2011	
2012	
2013	

2.1.6.4 Short- and Long-Term IPL Large Industrial Sales

The Large Industrial class consists of IPL's largest industrial customers. These customers face large, and usually planned, changes in their energy use. Therefore, the Large Industrial's sales forecast relies on communication with the customer account representatives and examination of historical sales.

2.1.6.5 Short- and Long-Term IPL Other Sales and Losses

The Other sales forecast includes the Municipal, Other Public Authorities, Interdepartmental, and Street Lighting rates. These classes are not formally modeled as they consist of less than four percent of total sales. The forecast for these classes are made based on recent historical data and on any known contract changes.

2.1.6.6 Long-Term IPL Residential

For residential sales, the model is based on annual observations. The independent variables used and their descriptions are as follows:

<u>Cooling Degree Days (CDD)</u> is a measure of annual cooling load.

<u>Real Price of Residential Electricity (RPRICE)</u> is the annual price of electricity in chain-weighted 2005 dollars.

<u>Iowa Gross State Product (IAGSP)</u> is a measure of economic activity in an area that approximates the service territory in chain-weighted 2005 dollars.

The model equation is as follows:

(Residential use per customer, (MWH*10000 customers)) =7,929+ 0.983*(CDD) – 1,493*(RPRICE) +18.8*(IAGSP) +e where e is an error term.

The model parameters are as follows:

Table 2.1.6g
Long-Term IPL Residential Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	7,929	18.93	0%
CDD	0.983	6.55	0%
RPRICE	-1,493	-5.23	0%
IAGSP	18.8	11.96	0%
R^2=0.926 Adj. R^2=0.917			

Growth rate forecast assumptions for households, personal income and electricity prices are shown in Table 2.1.6h, Long-Term IPL Residential Sales Model Assumed Growth Rates. Forecasts of the independent variables are based on:

- Values for Iowa Gross State Product are from IHS Global Insight;
- Electricity prices (real) are forecasted based on recent historical trends and long-term trended expectations. Historical prices are discounted with the consumption expenditure deflator as reported by the US Bureau of Economic Analysis; and
- The weather variables are the average weather from 1991-2010.

Table 2.1.6h
Long-Term IPL Residential Sales Model Assumed Growth Rates
(Filed Confidentially)

Year	IAGSP	RPRICE	Customers
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			

2.1.6.7 Long-Term IPL Commercial Sales

For Commercial sales, the model is based on annual observations. The independent variables used and their descriptions are as follows:

Real Price of Electricity (CPRICE) is the approximate annual price of electricity, in chain-weighted 2005 dollars, for the commercial class.

Iowa Gross State Product (IAGSP) is a measure of economic activity in an area that approximates the service territory in chain-weighted 2005 dollars.

The model equation is as follows:

(Commercial MWH*1000/Customers)= 26.3 – 10.2*(CPRICE) + 0.247*(IAGSP) + e

where e is an error term.

The model parameters are as follows:

Table 2.1.6i
Long-Term IPL Commercial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
Constant	26.3	11.3	0%
CPRICE	-10.2	-6.99	0%
IAGSP	0.247	20.5	0%
R^2= 0.985 Adj. R^2=0.984			

Growth rate forecast assumptions for prices and customers are shown in Table 2.1.6j, IPL Long-Term Commercial Sales Model Assumed Growth Rates. Forecasts of the independent variables are based on:

- Change in the number of customers is based on a trend forecast;
- Values for Iowa Gross State Product are from IHS Global Insight; and
- Electricity prices (real) are based on recent trends in the historical data and long-term trended expectations. Historical prices are discounted with the consumption expenditure deflator as reported by the US Bureau of Economic Analysis.

Table 2.1.6j
Long-Term IPL Commercial Sales Model Assumed Growth Rates
(Filed Confidentially)

Year	CPRICE	IAGSP	Customers
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			

2.1.6.8 Long-Term IPL Industrial Sales

For Industrial sales, the model is based on annual observations. Industrial sales are sales to the Industrial Revenue Class less the sales to the Large Industrial class. The independent variables used and their descriptions are as follows:

Iowa Gross State Product (IAGSP) is a measure of economic activity in an area that approximates the service territory in chain-weighted 2005 dollars.

Real Industrial Price of Electricity (IPRICE) is the annual price of electricity in chain-weighted 2005 dollars, for the industrial class less large industrial customers.

The model equation is as follows:

(LGS mWh/cust) = 3,619 – 2,689*(IPRICE) + 1.35*(IAGSP) + e

where e is an error term.

The model parameters are as follows:

Table 2.1.6k
Long-Term IPL Industrial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
Constant	3,619	21.0	0%
IPRICE	-2,689	-16.6	0%
IAGSP	1.35	1.27	21.5%
R^2= 0.953 Adj. R^2=0.949			

Growth rate forecast assumptions for Gross State Product, Industrial customers, and Industrial electrical prices are shown in Table 2.1.6l entitled Long-Term IPL Industrial Sales Model Assumed Growth Rates. Forecasts of the independent variables are based on:

- Values for Iowa Gross State Product are from IHS Global Insight;
- Industrial Customer forecast depends on historical growth rates; and
- Electricity prices (real) are forecasted using recent trends in the historical growth rates and long-term trended expectations.

Table 2.1.6l
Long-Term IPL Industrial Sales Model Assumed Growth Rates
(Filed Confidentially)

Year	IAGSP	Customers	IPRICE
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			

2.1.6.9 Transition between Short- and Long-Term Energy Models

The Short-term model is used for the immediate forecast. The Long-Term models are used to determine the growth rates in the extended forecast. Linking the two is a transition period where the growth rates are assumed to be between the short and long-term growth rates. This ensures a continuous forecast.

2.1.6.9 Summer Demand Forecast

The current IPL summer demand forecast is developed using a regression model to predict the long-term growth in the system demand requirements. No explicit deductions for DSM are taken in the model since the effects of current programs are captured in the historical data.

The demand model is the sum of the forecasted firm demand for 10 IPL large customers, large changes, and the IPL Basic model. Large Customer forecasts and large changes are based on personal discussions with representatives from IPL's large customers tempered by IPL's experience and evaluation of any information provided.

The IPL Basic model is the demand of all IPL retail firm customers. IPL Basic is forecasted using an econometric regression model. Total firm demand is divided by the number of customers to come up with the average demand per customer. This is used for the dependent variable in the regression equation. Descriptions of the independent variables follow:

<u>Real Personal Income Per Capita (PIPC)</u>: Real per capita personal income in Iowa in 2005 dollars.

<u>Real Summer Price of Electricity (PERSA):</u> The IPL price of electricity during the summer in 2005 dollars.

<u>Temperature Humidity Index (THIC):</u> This index is based on temperature and humidity on peak day, the previous two days, and the accumulated cooling degree days index over the four weeks leading up to the peak. This variable is included in the regression model rather than weather-normalizing the data beforehand.

<u>Union Electric Indicator (UE):</u> An indicator variable that recognizes that the addition of the former UE territory would impact the rate of growth of the IPL system peak.

The coefficient for each of the independent variables in the log-linear model is the elasticity. Thus the coefficient for real personal income per capita equals the income elasticity of electricity, and so on. The model equation follows:

ln(IPL Basic per Customer) = - 2.69 + (0.380 * ln(PIPC)) – (0.15 * ln(PERSA)) + (1.29*ln(THICDDI)) - 0.074*ln(UE) + e

where e is an error term.

The model parameters are as follows:

Table 2.1.6m
Summer Demand Parameters

Variable	Coefficient	T-Ratio	Prob>|T|
Constant	-2.69	-3.15	0%
LPIPC	0.381	4.71	0%
LPERSA	-0.15	-2.18	4%
LTHICDDI	1.29	5.65	0%
UE	-0.074	-2.02	5%
R^2 = 0.697 Adj. R^2 = 0.649			

The forecast for the temperature-humidity index assumes normal peak-day weather conditions.

2.1.6.10 Winter Demand Forecast

The winter demand forecast is a constant percentage of the summer demand forecast assuming normal weather. The historical ratio of summer demand to winter demand determines the percentage used. The summer demand forecast is much higher than the winter demand forecast.

2.1.7 Margins of Error

Reference: 199 IAC 35.9(1)

> ***e. A statement of the margins of error for each assumption or forecast.***

IPL has not conducted studies that would result in reasonable margins of error for each assumption given in Section 2.1.6. However, some general points can be made about forecasting margins of error.

First, the assumed future levels of each independent variable contain some error. The accuracy of the sales forecast depends in part on the accuracy of forecasts of prices and incomes in the IPL service area. As demonstrated in the high and low economic scenarios shown in table 2.1.8, variation in future input values would result in actual sales or energy above or below forecast even if the models were perfect predictors.

A second, more dramatic margin of error is associated with forecast of customer-installed cogeneration facilities, plant closings or new large customers. IPL may or may not know the timing of the load loss. In the latter case, IPL can only review the customer's economic opportunities.

Third, in a regression-based forecast, the assumed equation includes an error term. This term accounts for all the dependent variables that are too insignificant or difficult to measure. While the error term is assumed to be zero, some deviation from forecast is attributable to the error term. As part of the annual development of its corporate revenue projections and capacity requirements, IPL provides confidence intervals on its long-term sales forecasts. The size of the 95 percent confidence intervals for the IPL long-term sales forecast are given in Table 2.1.7. Because the Large Customer and Resale portions of the sales forecast were not developed using regression analysis, the confidence intervals are not available.

Fourth, there is error in the estimation of the coefficients to be multiplied by the independent variables. While the regression finds the “best fit” based on the available data, this fit is still an estimation of the true relationship. Because the estimated relationships are assumed to hold during the forecast period, any difference between the estimated coefficient and the true coefficient will introduce error in the forecast. Using more data points allows better estimation of the true coefficients associated with each independent variable. Modeling choices reduce this error by reducing autocorrelation, multicollinearity and heteroscadasticity.

A fifth source of error stems from the assumption that historical data is a good predictor of future data. If there are fundamental changes occurring in the source data that are not explicitly accounted for in the model, there will be error in the forecast.

Table 2.1.7
IPL Sales Model 95% Confidence Intervals

Year	Residential +/- MWH	Commercial +/- MWH	Industrial +/- MWH
2012	150	156	397
2013	159	164	409
2014	175	176	430
2015	179	183	443
2016	181	188	453
2017	184	192	460
2018	185	195	466
2019	187	199	474
2020	189	203	480
2021	191	206	487
2022	192	208	491
2023	193	211	497
2024	196	216	505
2025	198	220	514
2026	200	224	521
2027	202	228	529
2028	205	233	539
2029	208	239	550
2030	212	246	563

2.1.8 Scenario and Sensitivity Analyses

Reference: 199 IAC 35.9(1)

> ***f. An explanation of the results of sensitivity analyses performed, including a specific statement of the degree of sensitivity of estimated need for capacity to potential errors in assumptions, forecasts and data. The utility may present the results and an explanation of other methods of assessing forecast uncertainty.***

IPL's forecast for the summer demand is based on a log-linear econometric model, so the coefficient of each independent variable is the elasticity of that variable with respect to the dependent variable. As elasticities, these coefficients are by definition the ratio of the percent change of the dependent variable to the percent change in the various independent variables.

IPL's energy models (Residential, Commercial, and Industrial) are based on linear econometric models. Therefore, the coefficient reflects the MWH change in the dependent variable due to a one unit change in the independent variable.

IPL performed two scenarios this year as part of its forecast process. These two scenarios included a 0.5 percent increase (50 basis points) and a - 0.5 percent decrease in the growth rate of Iowa Real Personal Income, above and below, respectively, the base case assumption for each year. The results of these analyses on the long-term energy forecasts are shown in Tables 2.1.8.

Table 2.1.8
Income Scenarios
IPL Total Energy Forecast

YEAR	LOW INCOME ENERGY	BASE ENERGY	HIGH INCOME ENERGY
2012	16,583	16,612	16,641
2013	16,652	16,702	16,752
2014	16,332	16,415	16,498
2015	16,438	16,554	16,671
2016	16,566	16,715	16,866
2017	16,718	16,897	17,078
2018	16,848	17,056	17,268
2019	16,997	17,235	17,479
2020	17,136	17,405	17,682
2021	17,271	17,572	17,883
2022	17,387	17,719	18,064
2023	17,518	17,883	18,263
2024	17,669	18,068	18,486
2025	17,824	18,258	18,717
2026	17,960	18,430	18,927
2027	18,107	18,614	19,152
2028	18,270	18,816	19,399
2029	18,441	19,027	19,656
2030	18,626	19,255	19,934
2031	18,813	19,486	20,215

APPENDIX C.2

Interstate Power and Light Company

Natural Gas Forecasts

November 30, 2012

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Reference: 199 IAC 35.11

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

The current five-year gas forecast was produced during September and October 2011.

3.0 Forecasts and Class Loads

Reference: 199 IAC 35.10(1)

Pursuant to this rule, IPL provides its load forecast, including information specififying forecasted demand and energy use on a calendar year basis

Section 2.2, Class Load Data, is provided here
Section 3.1, Forecasts - Gas, is provided here

3.1 FORECASTS - GAS

Reference: 199 IAC 35.10(1)

Pursuant to this rule, IPL provides its forecast of demand and transportation volumes, including information specifying its demand and transportation volume forecasts.

3.1.1 Class Annual Throughput and Peak Day

Reference: 199 IAC 35.10(1)"a"

A statement in numerical terms of the utility's current 12-month and five-year forecasts of total annual throughput and peak day demand, including reserve margin, based on the PGA year by customer class. The forecasts shall not include the effects of the proposed energy efficiency programs in subrule 35.8(8), but shall include the effects to date of current ongoing utility energy efficiency programs.

The five-year peak-day demand forecast is included as Table 3.1.1a. Historical actual data reflects usage on the peak day, while forecasted usage is based on the design day. The current 12-month forecast of throughput is found in Table 3.1.1b, annual class level throughput can be seen in Tables 3.1.2b. These forecasts include firm and interruptible throughput. Table 3.1.1c presents the reserve margin. Tables 3.1.3g to 3.1.3l include the five-year forecasted throughput.

All forecasts include the effects of energy efficiency programs approved by the Board in Docket No. EEP-08-1.

Table 3.1.1a
Class Level Peak Day Demand
(Dth)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
ANR	Residential	22,216	29,470	24,998	23,583	21,048	30,015	29,965	29,914	29,864	29,813
	General Service	11,496	15,495	13,377	12,499	11,425	16,293	16,265	16,238	16,210	16,183
	Large General Service	651	930	833	650	724	1,032	1,031	1,029	1,027	1,026
	Direct Contract	0	0	0	0	0	0	0	0	0	0
	Company Use	90	104	80	84	86	123	122	122	122	122
	Total firm	34,452	45,999	39,288	36,816	33,283	47,463	47,383	47,303	47,223	47,144
	Losses	166	231	197	185	167	238	238	237	237	237
	Purchases	34,619	46,230	39,485	37,001	33,450	47,701	47,621	47,540	47,460	47,380

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
NNG	Residential	77,923	98,574	98,214	83,438	79,410	113,167	113,162	113,156	113,151	113,146
	General Service	35,142	49,236	49,035	43,583	39,082	55,696	55,693	55,690	55,688	55,685
	Large General Service	316	583	643	522	446	636	636	636	636	635
	Direct Contract	40	40	40	40	40	40	40	40	40	40
	Company Use	245	282	676	291	232	331	331	331	331	331
	Total firm	113,666	148,715	148,608	127,874	119,210	169,870	169,861	169,853	169,845	169,837
	Losses	571	747	746	555	598	852	852	852	852	852
	Purchases	114,237	149,462	149,354	128,429	119,808	170,722	170,713	170,705	170,697	170,689

Table 3.1.1a (Cont.)
Class Level Peak Day Demand
(Dth)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
NGPL	Residential	37,738	52,457	45,951	38,977	36,372	36,557	36,511	36,464	36,417	36,371
	General Service	20,313	27,769	25,307	22,283	21,111	21,218	21,191	21,164	21,137	21,110
	Large General Service	2,145	1,295	1,566	1,717	1,892	1,902	1,899	1,897	1,894	1,892
	Direct Contract	350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
	Company Use	96	217	186	192	297	299	298	298	297	297
	Total firm	60,642	83,088	74,360	64,519	61,022	61,326	61,249	61,173	61,096	61,020
	Losses	305	417	367	317	300	302	301	301	300	300
	Purchases	60,947	83,505	74,727	64,836	61,322	61,627	61,550	61,474	61,397	61,320

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total	Residential	137,877	180,501	169,163	145,998	136,830	179,740	179,637	179,535	179,432	179,330
	General Service	66,951	92,500	87,719	78,365	71,618	93,207	93,150	93,092	93,035	92,979
	Large General Service	3,112	2,808	3,042	2,889	3,062	3,570	3,565	3,561	3,557	3,553
	Direct Contract	390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
	Company Use	431	603	942	567	615	752	751	751	750	749
	Total firm	208,760	277,802	262,256	229,209	213,515	278,658	278,493	278,329	278,165	278,001
	Losses	1,042	1,395	1,310	1,057	1,065	1,392	1,391	1,390	1,389	1,389
	Purchases	209,803	279,197	263,566	230,266	214,580	280,050	279,884	279,719	279,554	279,390

Table 3.1.1b
2012 Monthly Sales
(000's Dth)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	2,893	2,345	1,897	862	591	281	261	221	371	625	1,701	2,538	14,586
Commercial	1,698	1,476	1,175	600	382	331	274	249	372	710	1,118	1,549	9,935
Industrial	352	313	304	231	195	212	179	175	261	292	426	304	3,246
Transport	2,661	2,461	2,441	2,286	2,167	2,076	1,994	1,783	1,843	2,312	2,339	2,526	26,888
Company Use	1	1	1	0	0	0	0	0	0	0	0	1	5
Interdepartmental	1	0	0	0	2	1	5	2	0	2	0	1	15
Total	7,606	6,598	5,819	3,980	3,336	2,900	2,713	2,431	2,847	3,941	5,585	6,919	54,675

Table 3.1.1c
Reserve Margin Forecast
(Filed Confidentially)

Pipeline	Year	Firm Forecast	Capacity Forecast	Reserve Forecast
ANR	12-13	47,701		
	13-14	47,621		
	14-15	47,540		
	15-16	47,460		
	16-17	47,380		
NGPL	12-13	61,627		
(2)	13-14	61,550		
(2)	14-15	61,474		
(2)	15-16	61,397		
(2)	16-17	61,320		
NNG	12-13	170,722		
(1,2)	13-14	170,713		
(1,2)	14-15	170,705		
(1,2)	15-16	170,697		
(1,2)	16-17	170,689		

(1) The Mason City area can be served from both NNG and NBPL
(2) Backup demand, or Direct Contract, is included as Capacity in this table

<u>3.1.2 Five Year Historical Peak Demands</u>

Reference: 199 IAC 35.10(1)"b"

A statement in numerical terms of the utility's highest peak day demand and annual throughput for the past five years by customer class.

The highest peak day demand and annual throughput for the past five years, by class, is presented in Tables 3.1.2a and 3.1.2b respectively below. (Note: Table 3.1.2a reports highest peak based on <u>firm</u> <u>only</u>; other years may show higher totals due to interruptible and transport volumes.)

Table 3.1.2a
Highest Firm Day Demands, by Customer Class, in Dth/day

Class	**Actual Demand 1/15/2009**
Firm:	
Residential	180,501
General Service	92,500
Large General Service	2,808
Direct Contract	1,390
Company Use	+ 603
Total Firm	277,802
Interruptible Plus Losses	+ 1,395
Total Peak Demand	279,197

Table 3.1.2b
Annual Sales History
(000's of Dth)

Class	12-11	10-11	09-10	08-09	07-08
Residential	12,061	15,353	15,267	15,949	16,462
Commercial	8,735	10,400	10,767	11,211	11,366
Industrial	2,321	2,881	3,392	3,812	3,468
"Co Use & Interdepartmental"	335.2149	297	278	519	371
Transportation	28,272	27,955	27,641	31,941	35,088

3.1.3 Forecast Comparisons

Reference: 199 IAC 35.10(1)"c"

A comparison of the forecasts made for the preceding five years to the actual and weather-normalized peak day demand and annual throughput by customer class including an explanation of the weather-normalization procedure.

See Table 3.1.3 below for all required data. Note that actual peak day demand data are available only for large volume customers. Actual peak day demands for small volume customers are estimated using monthly usage and weather data.

IPL weather-normalizes its class-level peak data by first estimating the weather sensitive use per customer using each pipeline's peak day, customers and actual weather. Then the class level peak is estimated using weather sensitive user per customer and design day weather.

IPL weather-normalizes its throughput using monthly class level weather normalization factors based on its system weather normalization. The IPL system weather normalization stems from the difference between actual and normal weather, the actual customer counts, and a regression analysis on class level monthly use per customer. The IPL system weather normalization factors are multiplied by the IPL-Iowa throughput to develop weather-normalized IPL-Iowa throughput.

Table 3.1.3a
Residential-Peak (Dth)

Year	Actual	Weather-Normalized	Fcst 2012	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007
07-08	137,877	193,354						213,489
08-09	180,501	184,128					208,833	214,046
09-10	169,163	206,424				207,082	209,502	215,035
10-11	145,998	189,028			205,233	207,339	210,175	216,032
11-12	136,830	185,334		191,885	205,291	207,597	210,852	217,035
12-13			179,740	191,887	205,345	207,857	211,532	
13-14			179,637	191,889	205,400	208,117		
14-15			179,535	191,891	205,455			
15-16			179,432	191,894				
16-17			179,330					

Table 3.1.3b
General Service-peak (Dth)

Year	Actual	Weather-Normalized	Fcst 2012	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007
07-08	66,951	94,394						102,047
08-09	92,500	94,262					101,238	102,313
09-10	87,719	105,916				100,390	101,546	102,775
10-11	78,365	100,724			104,810	100,508	101,857	103,240
11-12	71,618	95,398		103,047	104,838	100,627	102,169	103,709
12-13			93,207	103,049	104,864	100,747	102,483	
13-14			93,150	103,051	104,890	100,867		
14-15			93,092	103,053	104,916			
15-16			93,035	103,056				
16-17			92,979					

Table 3.1.3c
Large General Service-peak (Dth)

Year	Actual	Weather-Normalized	Fcst 2012	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007
07-08	3,112	3,112						4,849
08-09	2,808	2,808					4,358	4,855
09-10	3,042	3,042				4,350	4,370	4,863
10-11	2,889	2,889			3,132	4,356	4,382	4,870
11-12	3,062	3,062		3,827	3,130	4,363	4,394	4,878
12-13			3,570	3,828	3,129	4,369	4,406	
13-14			3,565	3,828	3,128	4,376		
14-15			3,561	3,829	3,126			
15-16			3,557	3,829				
16-17			3,553					

Table 3.1.3d
Direct Contract- peak (Dth)

Year	Actual	Weather-Normalized	Fcst 2012	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007
07-08	390	390						1,250
08-09	1,390	1,390					543	1,252
09-10	1,390	1,390				1,390	545	1,255
10-11	1,390	1,390			1,414	1,390	547	1,258
11-12	1,390	1,390		1,390	1,415	1,390	549	1,261
12-13			1390	1,390	1,416	1,390	551	
13-14			1390	1,390	1,418	1,390		
14-15			1390	1,390	1,419			
15-16			1390	1,390				
16-17			1390					

Table 3.1.3e
Company Use –peak (Dth)

Year	Actual	Weather-Normalized	Fcst 2012	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007
07-08	431	599						674
08-09	603	614					659	676
09-10	942	1,623				653	661	678
10-11	567	736			674	653	663	681
11-12	615	853		747	675	654	665	684
12-13			752	747	675	654	667	
13-14			751	747	675	655		
14-15			751	747	675			
15-16			750	747				
16-17			749					

Table 3.1.3f
Total-peak (Dth)

Year	Actual	Weather-Normalized	Fcst 2012	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007
07-08	208,761	291,849						322,309
08-09	277,802	283,191					315,630	323,143
09-10	262,256	318,395				313,864	316,624	324,607
10-11	229,209	294,767			315,263	314,247	317,624	326,082
11-12	213,515	286,037		300,896	315,348	314,631	318,629	327,567
12-13			278,658	300,900	315,429	315,017	319,640	
13-14			278,493	300,905	315,510	315,405		
14-15			278,329	300,910	315,592			
15-16			278,165	300,916				
16-17			278,001					

Table 3.1.3g
Residential- Sales (000's Dth)

Year	Actual	Weather-Normalized	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007	Fcst 2006
06-07	15,409	16,310						14,945
07-08	16,462	14,976					15,377	14,924
08-09	15,949	15,673				15,829	15,457	14,903
09-10	15,267	15,479			15,904	15,902	15,537	14,883
10-11	15,353	14,410		15,213	15,967	15,974	15,618	14,863
11-12			14,586	15,272	16,030	16,047	15,698	
12-13			14,586	15,332	16,093	16,119		
13-14			14,585	15,391	16,157			
14-15			14,584	15,450				
15-16			14,583					

Table 3.1.3h
Commercial Sales (000's Dth)

Year	Actual	Weather-Normalized	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007	Fcst 2006
06-07	10,424	10,904						10,170
07-08	11,366	10,633					10,018	10,156
08-09	11,211	10,938				10,566	10,097	10,148
09-10	10,767	10,868			10,546	10,720	10,177	10,135
10-11	10,400	9,876		10,066	10,694	10,891	10,257	10,120
11-12			9,946	10,160	10,880	11,051	10,337	
12-13			9,935	10,257	11,069	11,213		
13-14			9,925	10,355	11,262			
14-15			9,915	10,454				
15-16			9,905					

Table 3.1.3i
Industrial Sales (000's Dth)

Year	Actual	Weather-Normalized	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007	Fcst 2006
06-07	3,458	3,458						3,297
07-08	3,468	3,468					3,120	3,246
08-09	3,812	3,812				3,172	3,091	3,198
09-10	3,392	3,392			3,237	3,172	3,063	3,149
10-11	2,881	2,881		3,279	3,263	3,151	3,034	3,100
11-12			3,249	3,329	3,311	3,144	3,006	
12-13			3,246	3,380	3,360	3,134		
13-14			3,243	3,431	3,409			
14-15			3,239	3,484				
15-16			3,236					

Table 3.1.3j
Company Use and Interdepartmental (000's Dth)

Year	Actual	Weather-Normalized	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007	Fcst 2006
06-07	382	382						515
07-08	371	371					392	515
08-09	519	519				72	392	515
09-10	278	278			268	72	392	515
10-11	297	297		98	268	72	392	
11-12			148	136	268	72	392	
12-13			148	136	268	72		
13-14			148	136	268			
14-15			148	136				
15-16			148					

Table 3.1.3k
Transport Sales (000's Dth)

Year	Actual	Weather-Normalized	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007	Fcst 2006
06-07	32,163	32,163						31,621
07-08	35,088	35,088					24,184	32,231
08-09	31,941	31,941				24,441	24,009	32,839
09-10	27,641	27,641			23,064	24,065	24,668	33,467
10-11	27,955	27,955		26,709	23,425	24,531	25,326	34,108
11-12			27,220	26,723	23,789	24,436	26,002	
12-13			26,888	26,723	24,159	24,481		
13-14			27,777	26,723	24,534			
14-15			27,794	26,723				
15-16			27,798					

Table 3.1.3l
Total Sales (000's Dth)

Year	Actual	Weather-Normalized	Fcst 2011	Fcst 2010	Fcst 2009	Fcst 2008	Fcst 2007	Fcst 2006
06-07	61,836	63,217						60,548
07-08	66,755	64,536					53,091	61,072
08-09	63,432	62,883				54,080	53,046	61,603
09-10	57,345	57,658			53,019	53,931	53,837	62,149
10-11	56,886	55,419		55,365	53,617	54,619	54,627	62,191
11-12			55,149	55,620	54,278	54,749	55,436	
12-13			54,803	55,828	54,949	55,019		
13-14			55,678	56,036	55,630			
14-15			55,680	56,247				
15-16			55,670					

3.1.4 Transportation Forecast

Reference: 199 IAC 35.10(1)"d"

A forecast of the utility's demand for transportation volume for both peak day demand and annual throughput for each of the next five years.

See Table 3.1.1b for the forecast of annual transportation volumes. Projected peak day firm transportation requirements are zero decatherms (Dth) per day. All transport volumes are transported on an interruptible basis. Some transportation customers have elected firm back-up service. Currently there is 1,390 Dth of back-up service under contract in each year for the next five years.

3.1.5 Existing Contract Deliverability

Reference: 199 IAC 35.10(1)"e"

The existing contract deliverability by supplier, contract and rate schedule for the length of each contract.

Peak day firm deliverability, by service, is presented in Table 3.1.5.

Table 3.1.5
Peak Day/Contract Demand Levels For 2012-2013
(Filed Confidentially)

Pipeline/Zone	Contracts	Start Date	End Date	Winter Capacity	Total Capacity for Peak	Design Day Peak
IPL ANR						
						47,701
						-
	Total					47,701
IES NGPL						
						87,082
						(350)
	Total					
IPC NGPL						
IPC NGPL/NBPL						
IPC NGPL/NBPL						
						(1,000)
	Total					85,732
IPL NNG						
						170,722
						(40)
						170,682
				System Totals		304,115

Reserve Margin Calculation

*

** New/Revised Contract

3.1.6 Methods and Assumptions

Reference: 199 IAC 35.10(1)"f"

An explanation of all significant methods and data used, as well as assumptions made, in the current five-year forecast(s). The utility shall file all forecasts of variables used in its demand and energy forecasts. If variables are not forecasted, the utility shall indicate all sources of variable inputs.

IPL forecasts its sales using a regression model of monthly use per customer for the major gas classes. Monthly route level sales are matched to the heating degree days (HDD) for the same timeframe. The weighted average of the route level weather is divided into summer and winter HDD to form two of the independent variables in the regression anlysis. Other variables included in the regression are the price of gas, monthly indicator variables, and known data changes. Using forecasted variables of gas prices and normal weather in the regression model results in monthly predicted use per customer values. Multiplying these values by the forecasted number of customers creates a monthly class level forecast of gas sales. Modeled results may then be adjusted based on comparisons to recent sales data, or calendarization.

IPL's design day forecast begins with historical wintertime daily system gas. The daily system gas is then adjusted by subtracting transport dekatherm data by pipeline, zone, and jurisdiction, to develop regression models. Next, the daily system gas less transport is broken down to daily usage per customer. The total daily usage per customer for each separate pipeline, zone and jurisdictional combination is then regressed against daily

HDD to determine the coefficient per HDD. The model equations are as follows:

(A) Usage/Customer = intercept+coefficient (HDD)

(B) Total peak day usage = (A)*Forecasted number of customers

Finally an estimate of interruptible sales, based on prior history, is subtracted from (B) to obtain firm daily use.

3.1.7 Margins of Error

Reference: 199 IAC 35.10(1)"g"

A statement of the margins of error for each assumption or forecast.

Ninty-five percent confidence intervals on forecasted design day load by pipeline is found in Table 3.1.7 below.

Table 3.1.7
95% Confidence Intervals

Pipeline/Zone	Upper Limit	Lower Limit
ANR	52,591	42,811
NGPL	95,084	79,078
NNG	186,372	155,072

3.1.8 Scenario and Sensitivity Analysis

Reference: 199 IAC 35.10(1)"h"

An explanation of the results of the sensitivity analysis performed by the utility, including a specific statement of the degree of sensitivity of estimated need for capacity to potential errors in assumptions, forecasts, and data.

Based on data from the last ten heating seasons, the mean absolute percent error of the IPL gas peak forecast to the weather-normalized actual peak is 5.9 percent.