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September 30, 2008

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, BC
V6E 2N7

Attention: Ms. Leigha Worth, Barrister & Solicitor

Dear Ms. Worth:

**Re: Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (collectively the "Companies") 2008 Resource Plan**

**Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO") Information Request ("IR") No. 1**

On June 22, 2008, the Companies filed their consolidated 2008 Resource Plan. In accordance with Commission Order No. G-120-08 setting out the Regulatory Timetable, the Companies respectfully submit the attached response to BCOAPO IR No. 1.

If there are any questions regarding the attached, please contact the undersigned or Ken Ross at (604) 576-7343 or ken.ross@terasengas.com.

Yours very truly,

**TERASEN GAS INC.,**
**TERASEN GAS (VANCOUVER ISLAND) INC. and**
**TERASEN GAS (WHISTLER) INC.**

***Original signed:***

Tom A. Loski

Attachment

cc: Erica M. Hamilton, Commission Secretary, BCUC
Registered Parties (e-mail only)

**1. Reference: Exhibit B-1, Executive Summary, p. E-4 and p.18**

1.1 Please confirm that the projected increase in population growth in B.C., from 4.4M today to 5.4M in 2028, represents an annual average increase of 1.03% per year.

**Response:**

Terasen Gas confirms that the projected increase in population growth in B.C., from 4.4M today to 5.4M in 2028, represents an annual average increase of 1.03% per year.

**2. Reference: Exhibit B-1, Executive Summary, p. E-5, Figures ES-3 and ES-4**

2.1 Please provide a high-level explanation as to why in the low growth scenario demand growth is positive but peak day demand growth is negative.

**<u>Response:</u>**

In the low growth scenario, peak day demand is positive but annual demand growth is slightly negative over the planning period. The difference in growth is attributed to the assumption made in Peak Day Demand analysis of a constant peak use per customer rate throughout the planning period, whereas for annual demand analysis use per customer rates vary. The assumption of a constant peak use per customer rate is discussed further in BCUC IR 1.10.3

**3. Reference: Exhibit B-1, Executive Summary, p. E-9, Action Plan**

3.1 Please identify any benchmarks, targets, timelines, etc., that Terasen will use in evaluating the success of its action plan ex post.

**Response:**

For Action Item No. 1 on page 111 of Exhibit B-1 – Implement new EEC programs and continue research and planning for future EEC programming – Terasen Gas will implement benchmarks, targets and timelines as determined by the Terasen Gas 2008 EEC Application and associated regulatory process currently under way. For all other action items, defined timelines, benchmarks and targets are impractical at the Resource Planning stage since implementation must incorporate the timing of actions by other parties, the need for further studies or regulatory submissions, or the development of market conditions and trends. As with this 2008 Resource Plan (see pages 6 - 8 of Exhibit B-1), Terasen will report on the progress and success of its Action Plan in the next Resource Plan, expected to be submitted to the BCUC in 2010.

## 4. Reference: Exhibit B-1, p. 18

4.1 Terasen states that "EEC programs…cannot be expected to reverse demand growth." Given declining average use and the population growth projected, does Terasen Gas believe this statement holds true for the residential sector specifically?

**Response:**

The table below shows the changes in consumption projected as a result of EEC activity vs. the projected overall demand growth in 2008, 2009 and 2010, broken out into the residential and commercial sectors. It can be noted that the statement referenced above is true for all sectors in all three years, with the exception of the commercial sector in 2010, where volume impacts from EEC are projected to exceed projected demand growth. However, it should further be noted that for the residential and commercial sectors *combined*, savings from EEC activity will not reverse demand growth.

| | 2008 | | | 2009 | | | 2010 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Projected Demand Growth (TJ) | EEC Volumes (TJ) | EEC Volumes as a percentage of Demand Change | Projected Demand Growth (TJ) | EEC Volumes (TJ) | EEC Volumes as a percentage of Demand Change | Projected Demand Growth (TJ) | EEC Volumes (TJ) | EEC Volumes as a percentage of Demand Change |
| **Residential** | 1,336 | -23 | -1.72% | 695 | -52 | -7.53% | 340 | -37 | -10.76% |
| **Commercial** | 1,089 | -179 | -16.48% | 630 | -444 | -70.40% | 607 | -813 | -133.91% |
| **Total** | 2,425 | -202 | -8.34% | 1325 | -496 | -37.42% | 947 | -849 | -89.69% |

**5. Reference: Exhibit B-1, p. 21, Natural Gas Price Forecasts**

5.1 Please provide any information that relates to the accuracy of the price forecasts that GLJ or the EIA have historically provided.

**Response:**

It should be noted that Terasen Gas has included these third party forecasts in its Resource Plan since it does not itself undertake natural gas price forecasting and these are two sources that are publicly available and therefore not restricted from reproduction by proprietary rights. The purpose of including these forecasts is to provide stakeholders with an idea of what third party experts are speculating about gas prices. They offer an opinion, that being a directional notion, about where gas prices may be heading in the future. As such, Terasen Gas does not carry out detailed studies on the accuracy of these forecasts. In response to the request, however, Terasen Gas offers the following observations.

Terasen Gas notes that the Energy Information Administration ("EIA") does complete a retrospective report on its energy information forecasts, including natural gas supplies, demand and well head prices, titled Annual Energy Outlook Retrospective Review[1]. Table 8 from that report compares actual well head prices to EIA forecast prices up to and including 2007, and is provided as Attachment 5.1.

GLJ does not provide a retrospective report like EIA, however, for illustrative purposes the Company has re-created something similar by comparing GLJ's projected Nymex gas prices based on previous forecasts versus actual using current data for calendar years 2005 to 2008.

**GLJ Projected Nymex Futures Contract Price vs. Actual**

| Forecast Date | Calendar Year 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|
| Oct 2004 | 6.15 | 5.75 | 5.50 | 5.30 |
| Jul 2005 | | 7.25 | 6.80 | 6.50 |
| Apr 2006 | | | 8.98 | 8.02 |
| Jul 2007 | | | | 7.50 |
| Actual | 8.55 | 7.26 | 6.92 | 9.63 |

[1] http://www.eia.doe.gov/oiaf/analysispaper/retrospective/index.html

## 6. Reference: Exhibit B-1, p. 22, Natural Gas Price Forecasts

The evidence states that “[m]oving into the mid-term, these forecasts also account for the market expectation of lowering prices as production increases and transmission infrastructure expand to improve access to supplies.”

6.1 Please provide the assumptions embodied by these price forecasts in respect of (i) available physical supplies and (ii) specific transmission projects.

**Response:**

As stated in response to BCOAPO IR 1.5.1, Terasen Gas does not forecast natural gas prices and has included the two sourced forecasts as an indication to stakeholders of what others are saying about future gas prices. Terasen Gas is similarly not privy to the specific inputs to these forecasts and must rely on the commentary provided by these sources in regard to their forecasts to respond to this request. In terms of the EIA forecast, Terasen Gas has provided a portion of the EIA’s 2008 Annual Energy Outlook[2] included as Attachment 6.1, which discusses its gas price forecast. The reference case EIA price forecast assumes that natural gas supplies expand in accordance with the discussion provided in this attached document and includes the assumption that “sufficient transmission and distribution capacity will be built to accommodate the projected growth in natural gas consumption”[3].

As noted on their web site, GLJ Petroleum Consultants (“GLJ”) prepares Quarterly forecasts after “a comprehensive review of the information available. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers.” [4]

Neither forecast identifies specific transmission projects in its assumption that transmission projects will proceed to meet demand, however, the numerous transmission expansion proposals in the Pacific Northwest as outlined in Terasen Gas’ Resource Plan, Exhibit B-1, Table 6-1, p 84, provide examples of how the development of such infrastructure arises to keep pace with growth in demand.

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[2] Energy Information Administration, June 2008. Annual Energy Outlook 2008 with Projections to 2030. 111p. http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf

[3] Ibid. p.76

[4] http://www.gljpc.com/

**7. Reference: Ibid**

7.1 Please indicate whether these forecasts took into account the behaviour of long run pricing for crude oil since 2003, in real terms, or whether the forecasts did not consider this information relevant.

**Response:**

Please see Terasen Gas’ response to BCOAPO IR 1.5.1 and 1.6.1 above with regard to the use and purpose of including these two third party natural gas price forecasts. Terasen Gas recognizes that there is a relationship between the long run pricing for crude oil and natural gas; however, the degree to which this relationship influences each of the forecasts and the strength of the relationship assumed by each third party is not known. Figure 2-9, page 23 of Exhibit B-1 and the related discussion suggests that this relationship has been changing.

## 8. Reference: Exhibit B-1, p.23, Natural Gas Price Forecasts, Fig. 2-9

8.1 Please explain (i) whether there is any difference between the crude oil futures market and the natural gas futures market with respect to liquidity and terms of contracts traded, and (ii) whether futures prices in general are considered a good predictor of future spot prices in the natural gas market.

**Response:**

The crude oil futures market and the natural gas futures market are somewhat different with respect to liquidity and terms of contracts traded. The NYMEX (North American Mercantile Exchange) futures market for natural gas is a continental market, about 60 Bcf per day in size, and is a more seasonal market with greater demand in the winter months due to significant heating load requirements in Canada and the United States. The crude oil futures market, on the other hand, is a global market of almost 90 million barrels per day and is characterized by less seasonality, due to the demand for a mix of refined products produced from oil, such as heating oil, gasoline, diesel and residual fuel oil. Therefore, crude oil transactions would more likely be based on calendar year rather than summer or winter seasons commonplace in the natural gas market.

While the crude oil futures market trades on a larger scale than the natural gas futures, both are highly liquid markets with thousands of contracts traded each day. The following tables show the number of contracts traded in each market historically. For the natural gas market, one contract equals 10,000 MMBtu per day. For the crude oil market, one contract equals 1,000 barrels per day. The source for this information is NYMEX.

Natural Gas (introduced 4/3/90)

| Year | Daily Average | Annual Volume |
|---|---|---|
| 2008 (July) | 159,457 | 23,440,124 |
| 2007 | 118,200 | 29,786,318 |
| 2006 | 91,753 | 23,029,988 |
| 2005 | 76,265 | 19,142,549 |
| 2004 | 70,048 | 17,441,942 |
| 2003 | 76,148 | 19,037,118 |
| 2002 | 97,431 | 24,357,792 |
| 2001 | 47,457 | 16,468,355 |
| 2000 | 71,787 | 17,875,013 |
| 1999 | 76,661 | 19,165,096 |
| 1998 | 63,658 | 15,978,286 |
| 1997 | 47,316 | 11,923,628 |
| 1996 | 35,115 | 8,813,867 |
| 1995 | 32,347 | 8,086,718 |
| 1994 | 25,329 | 6,357,560 |
| 1993 | 18,686 | 4,671,533 |
| 1992 | 7,623 | 1,920,986 |
| 1991 | 1,654 | 418,410 |
| 1990 | 529 | 132,820 |

**Light, Sweet Crude Oil**

| Year | Daily Average | Annual Volume |
|---|---|---|
| 2008 (July) | 556,657 | 81,828,574 |
| 2007 | 482,246 | 121,525,967 |
| 2006 | 283,080 | 71,053,203 |
| 2005 | 237,651 | 59,650,468 |
| 2004 | 212,382 | 52,883,220 |
| 2003 | 181,748 | 45,436,931 |
| 2002 | 182,718 | 45,679,468 |
| 2001 | 149,028 | 37,530,568 |
| 2000 | 148,123 | 36,882,692 |
| 1999 | 151,440 | 37,860,064 |
| 1998 | 121,497 | 30,495,647 |
| 1997 | 98,299 | 24,771,375 |
| 1996 | 93,577 | 23,487,821 |
| 1995 | 94,456 | 23,613,994 |
| 1994 | 106,822 | 26,812,262 |
| 1993 | 99,474 | 24,868,602 |
| 1992 | 83,768 | 21,109,562 |
| 1991 | 83,027 | 21,005,867 |
| 1990 | 94,370 | 23,686,897 |
| 1989 | 81,812 | 20,534,865 |
| 1988 | 74,837 | 18,858,948 |
| 1987 | 57,864 | 14,581,614 |
| 1986 | 33,254 | 8,313,529 |
| 1985 | 15,923 | 3,980,867 |
| 1984 | 7,361 | 1,840,342 |
| 1983 | 1,692 | 323,153 |

Futures prices are reflective of current market forces, including all relevant supply and demand factors, and so represent the market's view of future spot prices. As the natural gas market is well-established, efficient and highly liquid, consistent differences in futures prices and ultimate future spot prices would represent trading opportunities that the marketplace would arbitrage away. Therefore, future prices in general are considered a good predictor of future spot prices in the natural gas market.

**9. Reference: Exhibit B-1, p. 29, Population Growth**

9.1 Over the next 20 years, Terasen Gas expects that the projected population increase of about 1M will translate into an additional 250K customers. Please provide the implicit penetration rate i.e., the ratio of new customers to potential new customers from the growth in population.

**Response:**

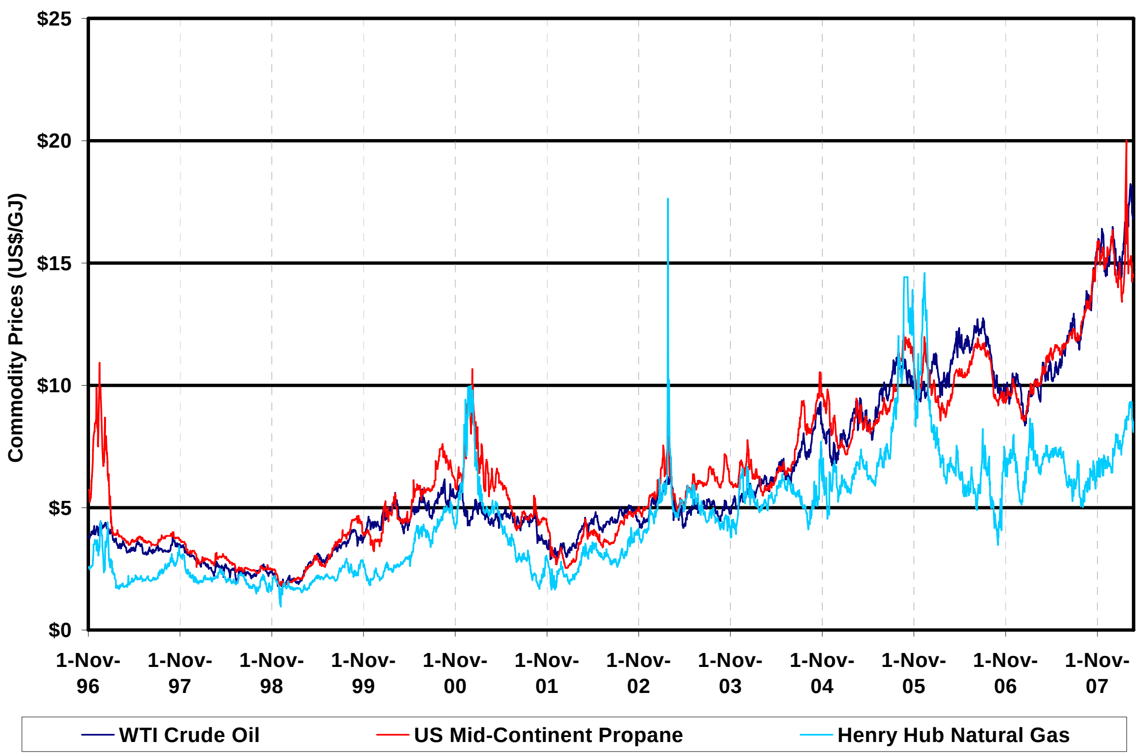
While the population is expected to grow by approximately one million people in BC over the next 20 years, this translates into an expected 580,000 additional households (as per BC Stats Household Formations Forecast – PEOPLE 32), which would represent potential customers to Terasen Gas. Given that, the implicit penetration rate is 250,000 / 580,000 or approximately 43% from the growth in population. 43% slightly overstates the true penetration rate as a portion of the additional 250,000 customers would result from existing homes converting to natural gas from other energy types, as discussed in Exhibit B-1, Appendix E.

## 10. Reference: Exhibit B-1, p. 24, Figure 2-10

10.1 Please provide the information shown on a graph with a linearly scaled horizontal (time) axis.

**<u>Response:</u>**

The intervals on the horizontal time axis of Figure 2-10 are linearly scaled, however the number of days between the points displayed on the scale is 500 days rather than 1 year. For convenience Figure 2-10 has been reproduced below where the only change is to have the horizontal scale display November 1st of each year.



**11. Reference: Exhibit B-1, p. 25, Natural Gas and Electric Comparison**

The text states that "[n]atural gas rates and bills are held constant based on the forward commodity prices discussed above displaying a moderate downwards trend."

11.1 Please (i) confirm that this refers to NYMEX prices settled to June 2, 2008 as in Fig. 2-9 if able to so confirm (otherwise please explain), and (ii) indicate whether Terasen Gas believes that the "forward" commodity prices are good predictors of future spot prices.

**Response:**

(i) Confirmed.

(ii) Forward commodity prices are reflective of what the market expects future commodity prices to be. Please see the response to BCOAPO IR 1.8.1

The text from p.25 of Exhibit B-1 quoted in the question refers to Figure 2-12 which holds natural gas rates constant (other than expected carbon tax increases) for two years into the future. Referencing the moderate downward trend in forward commodity prices was meant only to provide directional support to the assumption that holding gas rates constant was a reasonable one. Terasen Gas does not forecast commodity prices but as stated in the response to BCOAPO 1.8.1, the forward market does represent a good indicator of what the market collectively believes that prices will be in the future.

**12. Reference: Exhibit B-1, p. 30, Residential Use Trends and Appendix E**

12.1 The estimated decrease in residential use due to replacing low efficiency furnaces with high efficiency units is given as 0.9 GJ per residential customer yearly to 2020, after which Terasen Gas estimates the decline to slow to 0.2 GJ. Please provide the respective percentage decreases in annual consumption per residential customer that these declines represent.

**Response:**

The decline of approximately 0.9 GJ per residential customer yearly to 2020 represents a decline of approximately 0.9% per year for the Lower Mainland region and 1.2% for the Interior region. The decline of 0.2 GJ per residential customer from 2020 to 2028 represents a decline of approximately 0.2% per year for the Lower Mainland region and 0.3% for the Interior region.

**13. Reference: Exhibit B-1, p. 37, Annual Demand Forecast Results**

13.1 Please confirm that the overall consumption increase over the 20-year planning period from 189 PJ to 216 PJ represents an annual increase of 0.7% per year.

**Response:**

Terasen Gas confirms the overall consumption increase over the 20-year planning period represents an annual increase of 0.7% per year.

**14. Reference: Exhibit B-1, pp 40-42 and Appendix F, Design Day Demand**

14.1 Please indicate the sources of weather data (e.g., stations) used for constructing HDDs for each of the companies and how they are weighted (if they are).

**Response:**

Each region except for TGI Inland uses a single weather station for weather data. TGI Inland uses the simple average of weather data from four weather stations. The following table illustrates each of the companies and the sources of weather data used for constructing HDDs:

| **Company/Region** | **Weather Station** |
|---|---|
| TGI - Lower Mainland | Vancouver Airport |
| TGI - Inland | Simple average of data from the Prince George, Penticton, Kamloops, and Castlegar Airports |
| TGI - Columbia | Cranbrook Airport |
| TGI - Revelstoke | Revelstoke Airport |
| TG Fort Nelson | Fort Nelson Airport |
| TG Whistler | Whistler Weather Station |
| TGVI | Victoria Airport |

14.2 Please provide the simple correlation coefficient between HDD13 and HDD18.

**Response:**

When considering the temperatures experienced in the Lower Mainland region over the 2004-2006 contract years, the simple correlation between HDD13 and HDD18 is 0.995.

14.3 Please regress Daily Demand on HDD13 alone and provide the results of the OLS along with summary statistics.

**Response:**

The regression of daily sendout on HDD13 alone results in the following estimated parameters for the Lower Mainland region:

| Regression Results - LML Region | | | |
|---|---|---|---|
| **Year** | **Intercept** | **HDD13** | **Peak UPC** |
| 2004 | 0.2182 | 0.0585 | 1.7262 |
| 2005 | 0.1945 | 0.0600 | 1.7436 |
| 2006 | 0.2062 | 0.0591 | 1.7322 |
| **Average** | **0.2063** | **0.0592** | **1.7340** |

The measures of reliability associated with the above model are as follows:

| Regression Results - LML Region | | | |
|---|---|---|---|
| **Year** | **R-Square** | **F-Statistic** | **HDD13 P-Value** |
| 2004 | 94% | < .001 | < .001 |
| 2005 | 94% | < .001 | < .001 |
| 2006 | 94% | < .001 | < .001 |

The above measures of reliability indicate the model is statistically relevant, however, when compared to the current model employed, variances from actual would be higher and, therefore, Terasen Gas believes the model currently employed is more reasonable and that the model suggested in this information request would overestimate peak day demand.

14.4 Please repeat the calculation from BCOAPO IR 1.14.3 using HDD18 alone rather than HDD13.

**Response:**

The regression of daily sendout on HDD18 alone results in the following estimated parameters for the Lower Mainland region:

| Regression Results - LML Region | | | |
|---|---|---|---|
| **Year** | **Intercept** | **HDD18** | **Peak UPC** |
| 2004 | 0.1017 | 0.0443 | 1.4663 |
| 2005 | 0.0916 | 0.0437 | 1.4372 |
| 2006 | 0.0875 | 0.0450 | 1.4749 |
| **Average** | **0.0936** | **0.0443** | **1.4595** |

The measures of reliability associated with the above model are as follows:

| Regression Results - LML Region | | | |
|---|---|---|---|
| **Year** | **R-Square** | **F-Statistic** | **HDD18 P-Value** |
| 2004 | 95% | < .001 | < .001 |
| 2005 | 94% | < .001 | < .001 |
| 2006 | 94% | < .001 | < .001 |

The above measures of reliability indicate the model is statistically relevant, but the results are lower than those seen in the current model used by Terasen Gas. If this model were employed, the actual sendout of 656.2 TJ's experienced on January 14, 2005 would have been underestimated by 31.9 TJ's, as the above model would estimate 624.3 TJ's on that day (where the temperature was -5.5 degrees Celsius). Due to the significant negative consequences to customers of underestimating demand, this model would not be a good selection for peak day demand analysis.

14.5 On page F-4, do the results shown in Table 2 indicate that estimated send out is biased because for each year shown it exceeds actual send out or does it indicate that design day conditions did not materialize in any of the years?

**<u>Response:</u>**

The data in Table 2 do not indicate that send-out estimation is biased. Each of the variances is small except that shown in 2006, for which the larger variance is explained. Assessing the design day forecast model against actual design day conditions (which did not occur in the years presented) would provide better data, however, the model cannot account for all possible scenarios that could impact that design day demand such as the power outages that occurred in 2006 as described in Appendix F. It is important to note that as provider of last resort, Terasen Gas must ensure adequate infrastructure and supply to its customers. Therefore it is imperative that peak day demand not be underestimated.

14.6. Please explain why Design Day Demand for TGW under the low and reference forecasts is not expected to increase steadily (as shown in Fig. 3-10) unlike the forecasts for TGVI and TGI (as shown in Figs 3-9 and 3-11).

**<u>Response:</u>**

Design Day Demand for TGW is not expected to increase steadily, unlike the forecasts for TGVI and TGI, due to the assumptions made regarding increased conversion to alternative energy technologies in the TGW service area. These assumptions were made in consideration of the Municipality's Comprehensive Sustainability Plan, Sustainable Energy Strategy and related studies which set out the municipality's commitment that development in the community would move to greater reliance on renewable energy alternatives using natural gas as a supplementary energy fuel, and how quickly in each case that would occur. Due to TGW's smaller customer base located entirely within the Municipality, these individual strategic community plans have a greater influence on overall customer addition and use rate projections than in other regions served by the Terasen Gas Utilities. The impact of these plans on the TGW customer and demand forecasts was first developed in the TGW 2005 Resource Plan Update available on the Terasen Gas web site at www.terasengas.com. With such a comparatively small customer base, introducing alternative energy systems in this way causes fluctuations in demand growth that would otherwise appear smoothed out over a larger customer base.

**15. Reference: Exhibit B-1, p. 65 and p. 70, Potential New Load on ITS**

15.1 Please indicate what steps Terasen Gas will take to accommodate the new load if FortisBC determines that it requires the natural gas peaking facility in 2010-11.

**Response:**

To accommodate the potential new gas load for FortisBC's generation requirement, Terasen Gas would follow the normal steps in adding a new industrial customer load. These steps would involve establishing a firm transportation service agreement with the industrial customer either under a standard tariff rate or a negotiated rate subject to Commission approval..

As noted in the response to BCUC IR 1.20.0, FortisBC is considering the addition of a natural gas fired generation facility by the winter of 2012 at the earliest, and correspondingly Terasen Gas would need to accelerate its ITS facility addition schedule to match that for the generation facility as described in Section 5 of the Resource Plan (Exhibit B-1).

**16. Reference: Exhibit B-1, pp 78-79, Long Term Supply Planning Strategy and Appendix L**

16.1 Has Terasen Gas explored the possibility of entering into longer term contracts for storage services to mitigate renewal and price risks?

**Response:**

Terasen Gas currently has a suite of storage contracts ranging from terms of 2 years to 20 plus years. Generally, Terasen Gas feels that a mixture of short, mid and long-term storage contracts is optimal; however, storage service providers are in many cases reluctant to offer long term contracts.

In its current portfolio, TGI has contracts whose initial terms were greater than 10 years at Carbon in Alberta, with one of the 3 owners at Jackson Prairie ("JPS"),in Washington State and at Mist in Oregon. With the exception of the JPS agreement, these contracts were entered into a number of years ago. More recently, the owners of Jackson Prairie (other than Northwest Pipeline) and Mist are now much more reluctant to lease capacity at their facilities (to the extent there is capacity available) for more than two years. This reluctance appears to be a result of concern that core customers of facility owners are going to need more storage capacity in the near future, lack of clarity for certain regulatory rules and in the case of Mist, due to the uncertainties in the timing, cost and approvals for expansion of the existing facilities.

At Aitken Creek in northern BC, Terasen Gas has contracts with initial terms of 3 to 5 years such that about ¼ of the capacity expires on an annual basis beginning in 2010. Since the Aitken Creek facility represents the largest amount of storage capacity Terasen Gas has contracted for, this rolling expiration of medium term contracts provides a reasonable way to mitigate renewal and price risks.

In summary, the term of the contract Terasen Gas enters into is dependent on a number of factors including:

1. What is the maximum term that the storage provider is willing to enter into?
2. At the proposed price, for how long does Terasen Gas want to enter into the contract?
3. What escalation clauses are there for longer term contracts or is there an up-front premium?
4. Can Terasen Gas be guaranteed a cost effective firm redelivery service to match the storage term?

16.2 Please explain how the $0.25/GJ winter-summer differential is calculated. For example, is it based on actual prices ex post, actual summer prices versus futures prices for the heating season ex ante, or is it determined by some other means?

**Response:**

The $0.25/GJ differential calculated on page 78 of the 2008 Resource Plan is not a winter-summer differential but rather an increase in the Station 2 winter premium relative to the Alberta market price from 2006 to 2008. The calculation is derived from the difference in pricing of the Station 2 winter premium relative to the Alberta market price (AECO-NIT) at two different points in time. In September 2006 just prior to the start of winter 2006/07, Station 2 pricing was trading at a $0.13/GJ discount to AECO-NIT for the winter 2006/07 period. Conversely, in August 2008, just prior to the submission of this 2008 Resource Plan/, Station 2 was trading at a $0.12/GJ premium to AECO-NIT for the upcoming winter 2008/09 period. The difference between these two pricing differentials is $0.25/GJ.

16.3 Please indicate whether there has been any further increase in the winter-summer differential since this application was filed.

**Response:**

Please see response to BCOAPO IR 16.2. Since August 2008 there has been a slight increase in the Station 2 premium to AECO-NIT pricing for winter 2008/09. As of mid-September 2008, Station 2 was trading at a premium of $0.15/GJ over AECO-NIT.

With regard to the winter-summer differential (i.e. difference between winter 2008/09 and summer 2008 Station 2 pricing), this differential has changed considerably over the past six months. On March 31, 2008, just prior to the start of summer 2008, the Station 2 summer-winter differential was positive $1.03/GJ (i.e. forward winter 2008/09 Station 2 pricing trading $1.03/GJ over forward summer 2008 Station 2 pricing). However, as of mid-September 2008, this summer-winter differential is now negative $0.76/GJ, with forward winter 2008/09 Station 2 trading $0.76/GJ below the actual summer 2008 Station 2 index prices. The reason for this negative differential is the relatively high summer Station 2 prices, resulting from high crude oil prices, low storage levels coming out of winter 2007/08 and forecasts for a strong hurricane season, compared to relatively weaker winter 2008/09 forward prices, resulting from falling crude oil prices and recovering storage balances due to strong US production.

16.4 Please provide Terasen Gas' estimates as to the total daily supply of northern frontier gas that will become available over the planning period and the amount of Terasen Gas' supply that will ultimately be served by northern frontier gas.

**Response:**

Terasen Gas purchases its supply in BC at the Station 2 and Sumas trading hubs at which natural gas is pooled from various producing regions and locations.

The timing of northern frontier gas development has yet to be determined, including production, processing and pipeline capacity for delivery to market. Terasen Gas anticipates that the pooled supply of gas coming to the BC marketplace may contain some portion of northern frontier gas, however, as of yet, there has been no concrete information relating to the certainty of these regions as a supply source for BC.

The BC marketplace is, however, anticipating having access to supply from the recent developments occurring in northern BC with respect to the shale gas findings in Horn River and tight gas from the Montney region. Although the full nature of the reserves of these supply sources is still to be determined by the various exploration and development companies who have purchased land in these areas, gas from these sources is projected to be extensive and to be part of the BC supply pool as early as winter 2009.

# Attachment 5.1

## Table 8. Natural Gas Wellhead Prices, Projected vs. Actual

(current dollars per thousand cubic feet)

| | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AEO 1982 | 4.32 | 5.47 | 6.67 | 7.51 | 8.04 | 8.57 | | | | | | | | | | | | | | | | | |
| AEO 1983 | 2.93 | 3.11 | 3.46 | 3.93 | 4.56 | 5.26 | | | | | 12.74 | | | | | | | | | | | | |
| AEO 1984 | 2.77 | 2.90 | 3.21 | 3.63 | 4.13 | 4.79 | | | | | 9.33 | | | | | | | | | | | | |
| AEO 1985 | 2.60 | 2.61 | 2.66 | 2.71 | 2.94 | 3.35 | 3.85 | 4.46 | 5.10 | 5.83 | 6.67 | | | | | | | | | | | | |
| AEO 1986 | | 1.73 | 1.96 | 2.29 | 2.54 | 2.81 | 3.15 | 3.73 | 4.34 | 5.06 | 5.90 | 6.79 | 7.70 | 8.62 | 9.68 | 10.80 | | | | | | | |
| AEO 1987 | | | 1.83 | 1.95 | 2.11 | 2.28 | 2.49 | 2.72 | 3.08 | 3.51 | 4.07 | | | | | 7.54 | | | | | | | |
| AEO 1989* | | | | 1.62 | 1.70 | 1.91 | 2.13 | 2.58 | 3.04 | 3.48 | 3.93 | 4.76 | 5.23 | 5.80 | 6.43 | 6.98 | | | | | | | |
| AEO 1990 | | | | | 1.78 | 1.88 | | | | | 2.93 | | | | | 5.36 | | | | | 9.15 | | |
| AEO 1991 | | | | | | 1.77 | 1.90 | 2.11 | 2.30 | 2.42 | 2.51 | 2.60 | 2.74 | 2.91 | 3.29 | 3.75 | 4.31 | 5.07 | 5.77 | 6.45 | 7.29 | 8.09 | 8.94 |
| AEO 1992 | | | | | | | 1.69 | 1.85 | 2.03 | 2.15 | 2.35 | 2.51 | 2.74 | 3.01 | 3.40 | 3.81 | 4.24 | 4.74 | 5.25 | 5.78 | 6.37 | 6.89 | 7.50 |
| AEO 1993 | | | | | | | | 1.85 | 1.94 | 2.09 | 2.30 | 2.44 | 2.60 | 2.85 | 3.12 | 3.47 | 3.84 | 4.31 | 4.81 | 5.28 | 5.68 | 6.05 | 6.46 |
| AEO 1994 | | | | | | | | | 1.98 | 2.12 | 2.27 | 2.41 | 2.59 | 2.73 | 2.85 | 2.98 | 3.14 | 3.35 | 3.59 | 3.85 | 4.18 | 4.51 | 4.92 |
| AEO 1995 | | | | | | | | | | 1.89 | 2.00 | 1.95 | 2.06 | 2.15 | 2.40 | 2.57 | 2.90 | 3.16 | 3.56 | 3.87 | 4.27 | 4.56 | 4.85 |
| AEO 1996 | | | | | | | | | | | 1.63 | 1.74 | 1.86 | 1.99 | 2.10 | 2.19 | 2.29 | 2.38 | 2.48 | 2.59 | 2.72 | 2.84 | 2.97 |
| AEO 1997 | | | | | | | | | | | | 2.03 | 1.82 | 1.90 | 1.99 | 2.06 | 2.13 | 2.21 | 2.32 | 2.43 | 2.54 | 2.65 | 2.77 |
| AEO 1998 | | | | | | | | | | | | | 2.30 | 2.20 | 2.26 | 2.31 | 2.38 | 2.44 | 2.52 | 2.60 | 2.69 | 2.79 | 2.93 |
| AEO 1999 | | | | | | | | | | | | | | 1.98 | 2.15 | 2.20 | 2.32 | 2.43 | 2.53 | 2.63 | 2.76 | 2.90 | 3.02 |
| AEO 2000 | | | | | | | | | | | | | | | 2.15 | 2.23 | 2.27 | 2.32 | 2.40 | 2.51 | 2.66 | 2.81 | 2.97 |
| AEO 2001 | | | | | | | | | | | | | | | | 3.39 | 3.48 | 2.97 | 2.74 | 2.70 | 2.83 | 2.95 | 3.06 |
| AEO 2002 | | | | | | | | | | | | | | | | | 4.03 | 2.06 | 2.53 | 2.84 | 3.01 | 3.13 | 3.23 |
| AEO 2003 | | | | | | | | | | | | | | | | | | 2.79 | 3.26 | 3.13 | 3.15 | 3.15 | 3.30 |
| AEO 2004 | | | | | | | | | | | | | | | | | | | 4.97 | 4.00 | 3.72 | 3.73 | 3.86 |
| AEO 2005 | | | | | | | | | | | | | | | | | | | | 5.38 | 5.52 | 4.95 | 4.57 |
| AEO 2006 | | | | | | | | | | | | | | | | | | | | | 7.81 | 7.16 | 6.53 |
| AEO 2007 | | | | | | | | | | | | | | | | | | | | | | 6.87 | 7.00 |
| AEO 2008 | | | | | | | | | | | | | | | | | | | | | | | 6.37 |
| Actual | 2.51 | 1.94 | 1.67 | 1.69 | 1.69 | 1.71 | 1.64 | 1.74 | 2.04 | 1.85 | 1.55 | 2.17 | 2.32 | 1.96 | 2.19 | 3.68 | 4.00 | 2.95 | 4.88 | 5.46 | 7.33 | 6.40 | 6.39 |
| Average Absolute Difference (All AEOs) | 0.6 | 1.3 | 1.6 | 1.7 | 1.8 | 1.9 | 0.9 | 1.0 | 1.0 | 1.3 | 3.0 | 1.0 | 1.1 | 1.3 | 1.4 | 1.7 | 1.0 | 0.8 | 1.6 | 1.9 | 3.1 | 2.3 | 2.2 |

## Table 8. Natural Gas Wellhead Prices, Projected vs. Actual

(percent difference)

| | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AEO 1982 | 72.0 | 182.1 | 299.6 | 344.6 | 375.6 | 401.0 | | | | | | | | | | | | | | | | | |
| AEO 1983 | 16.7 | 60.1 | 107.4 | 132.5 | 169.8 | 207.4 | | | | | 721.7 | | | | | | | | | | | | |
| AEO 1984 | 10.4 | 49.3 | 92.3 | 114.6 | 144.6 | 180.1 | | | | | 501.7 | | | | | | | | | | | | |
| AEO 1985 | 3.6 | 34.4 | 59.0 | 60.2 | 74.2 | 95.9 | 135.0 | 156.3 | 150.1 | 215.4 | 330.3 | | | | | | | | | | | | |
| AEO 1986 | | -10.8 | 17.1 | 35.4 | 50.5 | 64.4 | 91.9 | 114.2 | 112.9 | 173.4 | 280.3 | 213.0 | 231.9 | 339.9 | 341.8 | 193.4 | | | | | | | |
| AEO 1987 | | | 9.6 | 15.2 | 24.6 | 33.5 | 51.5 | 56.6 | 51.0 | 89.7 | 162.9 | | | | | 105.0 | | | | | | | |
| AEO 1989* | | | | -4.1 | 0.6 | 11.4 | 29.9 | 48.1 | 49.1 | 88.1 | 153.5 | 119.5 | 125.3 | 195.8 | 193.7 | 89.7 | | | | | | | |
| AEO 1990 | | | | | 5.3 | 10.2 | | | | | 89.1 | | | | | 45.8 | | | | | 24.9 | | |
| AEO 1991 | | | | | | 3.5 | 15.8 | 21.3 | 12.8 | 30.6 | 61.7 | 19.9 | 17.9 | 48.5 | 50.2 | 1.8 | 7.8 | 71.9 | 18.2 | 18.1 | -0.6 | 26.5 | 39.9 |
| AEO 1992 | | | | | | | 2.8 | 6.2 | -0.4 | 16.1 | 51.6 | 15.7 | 18.2 | 53.7 | 55.1 | 3.5 | 5.9 | 60.5 | 7.7 | 5.8 | -13.1 | 7.6 | 17.4 |
| AEO 1993 | | | | | | | | 6.1 | -5.1 | 13.0 | 48.5 | 12.4 | 12.0 | 45.2 | 42.7 | -5.8 | -3.9 | 45.9 | -1.4 | -3.4 | -22.5 | -5.4 | 1.1 |
| AEO 1994 | | | | | | | | | -2.8 | 14.9 | 46.2 | 11.0 | 11.5 | 39.2 | 30.4 | -19.0 | -21.5 | 13.4 | -26.4 | -29.5 | -42.9 | -29.5 | -23.1 |
| AEO 1995 | | | | | | | | | | 2.3 | 28.9 | -10.0 | -11.0 | 9.8 | 9.6 | -30.2 | -27.6 | 7.1 | -27.1 | -29.1 | -41.8 | -28.7 | -24.1 |
| AEO 1996 | | | | | | | | | | | 5.2 | -19.8 | -19.7 | 1.6 | -3.9 | -40.4 | -42.8 | -19.4 | -49.3 | -52.6 | -62.9 | -55.7 | -53.6 |
| AEO 1997 | | | | | | | | | | | | -6.3 | -21.4 | -2.8 | -9.2 | -43.9 | -46.6 | -25.0 | -52.5 | -55.5 | -65.3 | -58.5 | -56.7 |
| AEO 1998 | | | | | | | | | | | | | -1.0 | 12.1 | 3.0 | -37.2 | -40.5 | -17.1 | -48.4 | -52.5 | -63.3 | -56.3 | -54.2 |
| AEO 1999 | | | | | | | | | | | | | | 0.9 | -1.9 | -40.1 | -42.1 | -17.8 | -48.1 | -51.8 | -62.4 | -54.6 | -52.8 |
| AEO 2000 | | | | | | | | | | | | | | | -2.0 | -39.3 | -43.3 | -21.4 | -50.9 | -54.0 | -63.7 | -56.0 | -53.5 |
| AEO 2001 | | | | | | | | | | | | | | | | -7.8 | -12.9 | 0.8 | -43.9 | -50.5 | -61.4 | -53.9 | -52.1 |
| AEO 2002 | | | | | | | | | | | | | | | | | 0.6 | -30.1 | -48.1 | -47.9 | -59.0 | -51.1 | -49.4 |
| AEO 2003 | | | | | | | | | | | | | | | | | | -5.6 | -33.2 | -42.8 | -57.1 | -50.8 | -48.3 |
| AEO 2004 | | | | | | | | | | | | | | | | | | | 1.9 | -26.8 | -49.3 | -41.8 | -39.6 |
| AEO 2005 | | | | | | | | | | | | | | | | | | | | -1.4 | -24.7 | -22.7 | -28.5 |
| AEO 2006 | | | | | | | | | | | | | | | | | | | | | 6.5 | 11.9 | 2.2 |
| AEO 2007 | | | | | | | | | | | | | | | | | | | | | | 7.3 | 9.6 |
| AEO 2008 | | | | | | | | | | | | | | | | | | | | | | | -0.3 |
| Average Absolute Percent Difference (All AEOs) | 25.7 | 67.3 | 97.5 | 100.9 | 105.7 | 111.9 | 54.5 | 58.4 | 48.0 | 71.5 | 190.9 | 47.5 | 47.0 | 68.1 | 62.0 | 46.9 | 24.6 | 25.8 | 32.7 | 34.8 | 42.4 | 36.4 | 33.7 |

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* There is no report titled *Annual Energy Outlook 1988* due to a change in the naming convention of the *AEO* s.

Sources: Forecasts: *Annual Energy Outlook* , Mid-Price or Reference Case Projections, Various Editions.

Historical Data: Energy Information Administration, Annual Energy Review 2007, DOE/EIA-0384(2007) (Washington, DC, June 23, 2008) , Table 6.7.

# Attachment 6.1

DOE/EIA-0383(2008)
June 2008

# Annual Energy Outlook 2008

## With Projections to 2030

# For Further Information . . .

The *Annual Energy Outlook 2008* was prepared by the Energy Information Administration, under the direction of John J. Conti (john.conti@eia.doe.gov, 202-586-2222), Director, Integrated Analysis and Forecasting; Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284), Director, Demand and Integration Division; Joseph A. Beamon (jbeamon@eia.doe.gov, 202/586-2025), Director, Coal and Electric Power Division; A. Michael Schaal (michael.schaal@eia.doe.gov, 202/586-5590), Director, Oil and Gas Division; Glen E. Sweetnam (glen.sweetnam@eia.doe.gov, 202/586-2188), Director, International, Economic, and Greenhouse Gases Division; and Andy S. Kydes (akydes@eia.doe.gov, 202/586-2222), Senior Technical Advisor.

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The *Annual Energy Outlook 2008* will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early summer 2008. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available in early summer 2008, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System are available at web site http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation and will be updated for the *Annual Energy Outlook 2008* during 2008.

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# Annual Energy Outlook 2008

## With Projections to 2030

### June 2008

**Energy Information Administration**
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

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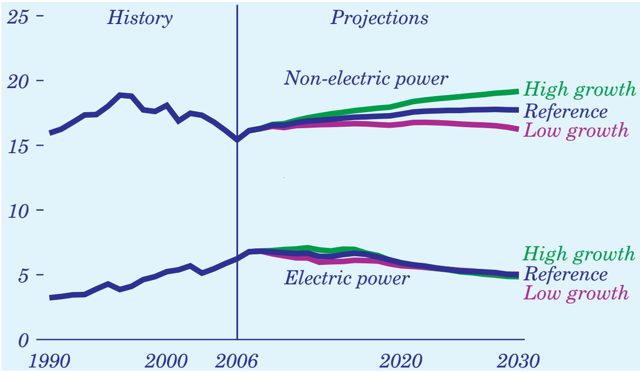
**www.eia.doe.gov/oiaf/aeo/**

## Natural Gas Use in Other Sectors Is More Sensitive to Economic Growth

***Figure 75. Natural gas consumption in the electric power and non-electric power sectors in alternative growth cases, 1990-2030 (trillion cubic feet)***

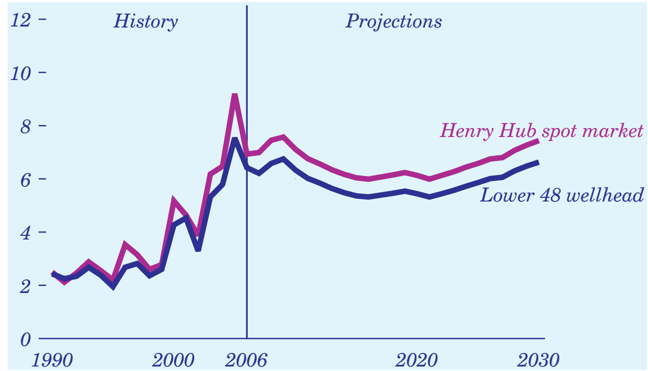



The largest variation in natural gas consumption in the residential, commercial, industrial, and transportation end-use sectors results from different assumptions about economic growth rates. In the high economic growth case, natural gas consumption in those end-use sectors is projected to total 19.2 trillion cubic feet in 2030. In the low growth case, the projected total in 2030 is 16.2 trillion cubic feet (Figure 75). Most of the difference between the projections in the two cases is attributable to the industrial sector, where growth in economic output has a greater impact on natural gas consumption than it does in the residential, commercial, and transportation sectors. In the industrial sector, projected natural gas consumption in 2030 varies from 7.2 trillion cubic feet in the low growth case to 9.0 trillion cubic feet in the high growth case.

Natural gas consumption in the electric power sector is sensitive to natural gas prices because other fuels, such as coal, can be substituted directly for natural gas in generating electricity. In the high and low economic growth cases, however, natural gas consumption in the electric power sector shows little variation from the reference case projection. Natural gas use for electricity generation in 2030 varies from 5.0 trillion cubic feet in the low growth case to 4.9 trillion cubic feet in the high growth case. In the high economic growth case, when natural gas consumption in the electric power sector begins to rise, natural gas prices increase significantly, and in response coal and nuclear power are substituted for natural gas.

## Projected Natural Gas Prices Fall from Current Levels Before Rising

***Figure 76. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2006 dollars per thousand cubic feet)***



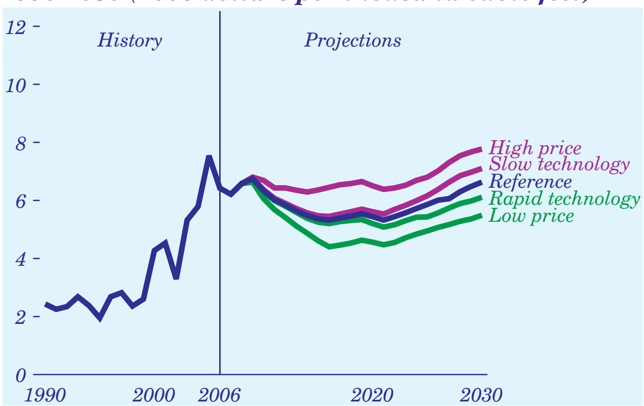

In the *AEO2008* reference case, lower 48 wellhead prices for natural gas are projected to decline from current levels to an average of $5.32 per thousand cubic feet (2006 dollars) in 2016, then rise to $6.63 per thousand cubic feet in 2030. Henry Hub spot market prices are projected to decline to $5.82 per million Btu ($5.99 per thousand cubic feet) in 2016 and then rise to $7.22 per million Btu ($7.43 per thousand cubic feet) in 2030 (Figure 76).

Current high natural gas prices are expected to stimulate the development of new gas supplies and constrain growth in natural gas consumption. Greater availability of natural gas supplies leads to a decline in prices through 2016. After 2016, wellhead natural gas prices increase largely as a result of the increased cost of developing the remaining U.S. natural gas resource base.

Natural gas prices in the reference case are determined largely by the cost of supplying natural gas from the remaining U.S. and Canadian resource base. In the future, however, the U.S. natural gas market is expected to become more integrated with natural gas markets worldwide, as a result of increased U.S. access to, and reliance on, LNG supplies from foreign sources. As a consequence, international market conditions will have a stronger influence on domestic natural gas prices in the United States, causing even greater uncertainty in future U.S. natural gas prices than would be the case if the United States relied exclusively on natural gas supplies from North America.

## Prices Vary With Resource Size and Technology Progress Assumptions

*Figure 77. Lower 48 wellhead natural gas prices, 1990-2030 (2006 dollars per thousand cubic feet)*

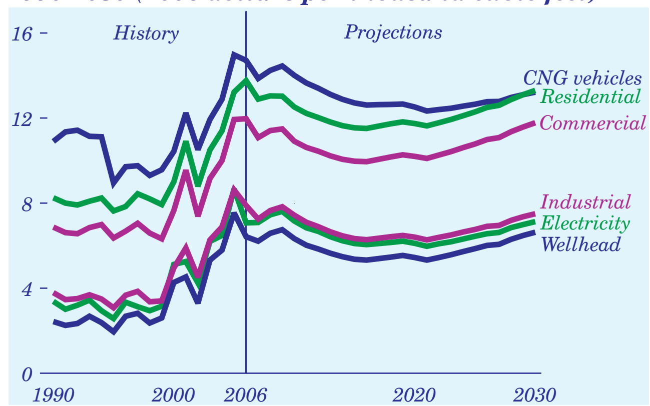



In the high price case, oil prices are assumed to be higher and the unproven natural gas resource base is assumed to be 15 percent smaller than the estimates used in the reference case. The low price case assumes lower oil prices and a 15-percent larger unproven resource base than in the reference case. A smaller domestic natural gas resource base increases exploration and production (E&P) costs, leading to higher natural gas prices. As a result, U.S. wellhead prices (and the price of LNG worldwide) are higher in the high price case and lower in the low price case than in the reference case (Figure 77). In 2030, domestic wellhead natural gas prices are projected to average $7.77 (2006 dollars) per thousand cubic feet in the high price case, compared with $5.49 per thousand cubic feet in the low price case.

Technological progress affects the future production of natural gas by reducing production costs and expanding the economically recoverable resource base. In the *AEO2008* reference case, the rate of improvement in natural gas production technology is based on the historical rate. The slow oil and natural gas technology case assumes an improvement rate 50 percent lower than in the reference case. As a result, future capital and operating costs are higher, causing the projected average wellhead price of natural gas to increase to $7.10 per thousand cubic feet in 2030. The rapid technology case assumes a rate of technology improvement 50 percent higher than in the reference case, reducing natural gas development and production costs. In the rapid technology case, wellhead natural gas prices are projected to average $6.11 per thousand cubic feet in 2030.

## Delivered Natural Gas Prices Follow Trends in Wellhead Prices

*Figure 78. Natural gas prices by end-use sector, 1990-2030 (2006 dollars per thousand cubic feet)*




Trends in delivered natural gas prices largely reflect changes in projected wellhead prices. In the *AEO2008* reference case, prices for natural gas delivered to the end-use sectors decline through 2016 as wellhead natural gas prices decline, then increase along with wellhead prices over the rest of the projection period (Figure 78).

Natural gas transmission and distribution margins in the industrial and electric power sectors fall over time, because production facilities in those sectors typically are connected directly to transmission pipelines, and pipeline rates are projected to fall as their depreciation expenses decline more rapidly than their costs increase. In the residential and commercial sectors, in contrast, transmission and distribution rates for natural gas rise over time, because increases in building efficiency reduce natural gas consumption at each building site, and distribution expenses thus are spread over a lower total volume of system throughput. As a result, average U.S. transmission and distribution margins increase slowly from 2006 to 2030 in the reference case.

All the *AEO2008* cases assume that sufficient transmission and distribution capacity will be built to accommodate the projected growth in natural gas consumption. If public opposition were to prevent infrastructure expansion, however, delivered prices could be higher than projected.