Minutes of the
Northwest Power Planning Council's

Natural Gas Advisory Committee

Held at the Council's Offices
851 SW Sixth Ave., Suite 1100, Portland, OR
February 28, 2002

The first meeting of the Natural Gas Advisory Committee for the Council's 5th power plan was called to order at 9:30 by chair Terry Morlan. There were 27 persons in attendance. The sign-up sheet is included as Attachment 1.

These minutes are not intended to reflect exactly what was said at the meeting, but rather what the Council staff heard as the basic advice during the meeting.

Attendance:

Members	Visitors
Rob Anderson	Dick Watson, NPPC
John Bridges	Bryan Mills ,EPIS, Inc.
Phil Carver	Peter Stiffler, Economic Insight, Inc.
Kevin Christie	Deborah Austin-Smith , EPIS, Inc.
Colin Coe	Ian MacDonald, BC Gas (for Cynthia Des Brisay)
Jeffrey Currie	
Byron Defenbach	
Bill Donahue	
Randy Friedman	
Rick Harper	
Reed Harris	
Jane Harrison	
David Hawk	
Jeff King	
Dan McAstocker	
Terry Morlan	
Greg Staple	
Paula Pyron	
Clay Riding	
Pat Scherzinger	
Peter Schwartz	
Sam Van Vactor	
Bill Wood	

Introductions:

Terry Morlan welcomed the members to the Natural Gas Advisory Committee (NGAC) meeting and thanked them for their willingness to serve on the committee and advise the Council of fuel related issues in its 5th power plan. Each attendee introduced himself to the group. Then Dick Watson, Power Planning Director, welcomed the group and gave a brief introduction to the power plan and the importance of information and assumptions about natural gas and other fuels to the power plan.

General Comments:

Terry Morlan asked for any general reactions to the draft forecast paper that the group had been sent before the meeting. There were some suggestions of factors that were not given adequate attention in the draft. These included: the role of storage in natural gas markets, existing and changing natural gas pipeline capacity into the region and effect on price differentials, the role of pipeline capacity release in the delivery of natural gas, and the need to more carefully define market pricing points in the analysis.

Natural Gas Price Forecast:

Wellhead Prices

Discussion of natural gas forecasts began with the wellhead price assumptions. The draft wellhead price forecast for the medium case started at $2.30 per million Btu in year 2000 dollars, increased to $2.50 by 2005, and then grew at 0.8 percent a year reaching $2.93 20 years later.

The gist of much discussion was that the committee felt that the draft forecasts were too low. There was an expectation that prices are likely to be in the $3 to $4 dollar range over the next 5 years. One member suggested $2.80 - $4.00 in the PNW, slightly higher in CA. Morlan asked what has changed in the last 2 years to make prices that have traded in the $2 range since the late 1980s, suddenly increase to the $3 to $4 dollar range for the five years and beyond. Below are some of the points that were made to support the expectation of higher prices.

- We have finished picking the low-hanging fruit of gas supplies. The marginal cost of new gas has increased. More drilling is required to replace reserves
- The marginal cost of new supplies may be around $2.75 One member stated that the futures market reflects replacement costs greater than $3.00; another stated that “market costs of production” are about $2.75, instead of the $2.25 of the recent past. However, increased volatility with high price spikes will increase the average cost of supplies over time (see volatility discussion below).
- Consumption levels have returned to the previous peak levels of the early 1970s. Strong growth is predicted going forward reaching levels of 30 Tcf in the next 20

years. Adding that much natural gas supply will require greater annual additions to reserves than in the past.

- Current prices have fallen quickly from 2000-2001 levels to near $2, but most view this as the result of a warm winter, economic recession, and robust storage inventories. Prices would be a dollar or more higher now with more normal winter conditions. Prices are not expected to stay this low for more than six to nine months. One member advised that because of this, this year's price would not be a good one to kick off a long-term forecast.
- Natural gas markets are becoming more of a just-in-time market. Both reserves and industry infrastructure have been shrinking through under investment. Inadequate infrastructure leads to growing volatility, which raises prices on average. Price cycles expected to get shorter and more severe. Further, increased volatility reduces industry financial performance and limits the capital available for investment in increased capacity, which adds to the inadequacy of investment and infrastructure. Increased volatility in markets is especially a problem given the trend toward shorter-lived wells.
- Historical prices are not viewed as relevant to forecasting the future. The natural gas world has changed and the past is not a reliable guide to the future.
- The futures market, which is currently above the mediun forecast, reflects increasing concern regarding replacement resources.

The committee discussed whether wellhead, or Henry Hub, price volatility would translate into volatility to natural gas consumers. One electricity generator reported buying a natural gas producer to reduce volatility. Use of financial hedges is also common to manage volatility.

The committee discussed how the Council might develop a short-term forecast reflecting volatility and merge it with a longer-term supply and demand based forecast of price trends. The potential usefulness of forward market prices to help forecast the next 4 or 5 years was discussed. It was pointed out that the NYMEX forward market, while transparent, is not the basis for all, or maybe even a large part, of fuel supply purchases by end-users or their suppliers. Over the counter transactions of varying lengths, many longer than four or five years, are common, but that market is less transparent. That is, it is more difficult to discover the average price at which such transactions occur.

Some alternative supplies of natural gas that might affect future markets were discussed. It was expected that LNG would become competitive at prices around $3.50 per million Btu, but that increased LNG imports are at least three to four years away. Some expected Mexican supplies to become available to U.S. markets in the future. The construction of pipelines to deliver Alaskan and frontier Canadian gas to the market is expected to be a key future source, but not likely to be financially feasible without substantially natural gas higher prices.

Regional Price Differentials

It was assumed in the medium draft forecast that the differential between the national wellhead price and the Canadian prices would be $ -.32. The committee stated that the Council needs to be more precise regarding the pricing points in Canada. Morlan responded that the $ -.32 is the Sumas differential and that the corresponding differential to Henry Hub prices would be $.12 more or $ -.44. For Aurora model purposes the Council had assumed that AECO prices would be $ .04 less than Sumas prices, with a Henry Hub differential of $ -.48.

There seemed to be some agreement among the committee members that the basis differentials were too high for the future. One member thought that $ -.25 would be the upper limit of average basis differential in the future. It was recognized that basis differentials are also volatile. Another member pointed out that basis differentials should probably be expected to decline over time as a result of additional transportation infrastructure development. It was agreed that there might be a limit to how small the basis differential to Canadian supplies might get, but little agreement on what that was. Some said that because of the amount of gas supply coming from Canada and the Rockies they would expect a continued advantage to Northwest consumers from lower natural gas prices relative to the rest of the country, especially the East Coast. Others noted that if the deep reserves in the Gulf or Mexican supplies became a large marginal supply of natural gas it might reduce the basis differential. In other words, it depends on the location of supply and demand. It was suggested that in trying to determine basis differentials, the more relevant historical period would be following 1992-93 when the natural gas bubble ended.

Several members believed that the same differentials could be used for all forecast levels. Several recommended that tables showing the annual prices for each pricing point be supplied in the final paper. There was expectation among several members that Station 2 in Northeastern BC will replace Sumas as a major pricing point. Greater competition would occur between AECO and Station 2, and prices at Sumas would depend more acutely on demand and might become more volatile. Some members thought that Station 2 prices might be expected to average something close to Chicago prices minus Alliance Pipeline costs. Others thought that Station 2 prices should be related to the AECO-C price.

One member suggested that Northwest prices be modeled as 58% Sumas/42% Rockies gas, trending to 65% Sumas/20% AECO/15% Rockies. Other members suggested that the price forecasts needed to be done separately for at least the east side of the Cascades and the West side. The California Energy Commission has separated the Northwest market into 5 areas; Kingsgate, Stanfield, Malin, Coastal, and utility delivered.

Morlan directed the committee's attention to Appendix B on the draft forecast paper where differentials used in the Aurora model are displayed. He asked the committee to

look at those differentials and provide comments, but did not want to take time to discuss in today's meeting.

Transportation Costs to End Users

Morlan explained that for gas consumers that rely on local distribution companies for the their gas supplies, retail prices are based on historical differences between wellhead prices and northwest retail prices. But for electric generation or large industrial consumers that buy their own gas, the Council attempts to estimate the cost of delivered natural gas based on various transportation cost components.

One component of those costs is the regional basis differential, which was discussed separately and summarized above. The next component discussed was the in-kind fuel charge. Morlan stated that the current assumption is 1.25 percent of the natural gas price, and that he understood that the percentage should have been applied to the regional gas price instead of the US wellhead price. The Council assumption was considered to be too low. Williams Northwest charges 1.5 percent from Sumas. Another 2 to 2.5% would need to be added to account for Canadian transport. Gas delivered from AECO would cost something like 2.75 percent, including Canadian and PG&E Gas Transmission Northwest charges.

The next component was pipeline capacity. The committee did not think interruptible pipeline transportation was relevant. There is very little gas transported on interruptible rates now. The corresponding non-firm concepts are capacity release markets or short-term firm, both of which are often quite inexpensive, but can also be very expensive under tight market conditions. Capacity release cost, on an experimental basis, can currently go well above firm capacity costs during tight market conditions. On average these costs might be substantially less than the $ .30 assumed in the draft forecast for interruptible pipeline costs.

The cost of firm pipeline capacity, both existing and incremental, was discussed. The draft forecast assumption was $ .30 per million Btu ($2000) for existing capacity and $ .36 for incrementally priced capacity. The committee thought both were too low. Their seemed to be some agreement that near-term future capacity on Williams Northwest would be about $ .36 excluding the in-kind fuel charge after current expansion projects are completed. Incremental capacity cost depends very much on the particular project. It was expected that these costs would generally increase over time, but the discussion was not clear about whether that was in nominal or real prices. The prices of some recent expansions are apparently in the $ .40 to $ .45 per million Btu range.

The committee compared the delivery costs from AECO to Kingsgate and Stanfield with those from Station 2 to Sumas. The cost to Sumas was $ .18 plus a 3.5 percent fuel charge. The cost to Kingsgate was $ .16. The cost to Stanfield would add another $.135 for a total Stanfield delivery cost of $ .295.

In later discussion, it was stated that industrial consumers arranging their own natural gas supplies and electric generators should be assumed to have the same costs up to the local city gate.

The draft forecast assumed that someone buying firm year-round natural gas supplies would pay a $ .30 premium. The committee had some trouble with this concept, but most seemed to agree that if a high capacity factor consumer were to buy gas that way the premium might be 5 or 6 cents. This might be the right amount to include in the fixed cost portion of the fuel cost.

King asked about the likely use of firm and non-firm natural gas supplies and transportation for electric generators. The discussion made it clear that this decision is very dependent on specific cases. The committee noted that need for firmness depended on location, access to alternative fuels, and access to storage. The need to contract on a firm basis for a peaking plant would very much depend on when during the year the plant would most likely operate. A plant running in the Northwest to meet peak summer loads could likely rely on pipeline capacity released by local distribution companies whose loads peak in the winter. A plant that operates at a low capacity factor, but holds firm pipeline capacity, would have a high pipeline cost on a dollar per million Btu basis. There was little agreement on what an a reasonable average assumption might be for firm/non-firm supply mix in a generic generation plant

At least one member said that 100% firm pipeline capacity is demanded by the bankers and is nearly universal for new projects. Another then indicated that a project might not carry 100% firm transportation, depending upon the situation, for example, if storage were available. However, “a significant portion” of Westside projects do carry full firm transportation and supply because of the significant spark spread and “a long-term view” on the part of the developers. One member proposed assuming 50% firm pipeline capacity + 50% capacity release at half of the firm rate. Someone else countered that we should assume 100% firm, using (from Sumas on Williams) a total of 32 cents of which 28 cents is fixed and 4 cents is variable, inclusive of GRI and ACA fees but exclusive of in-kind fuel costs. It was noted that the total is more like 40 cents when pipeline fuel costs are included. Several members then agreed that a total of 36 cents plus pipeline fuel charges would be a good compromise cost once current pipeline expansion projects are completed.

It was noted that single cycle combustion turbines intended for meeting only peak loads cannot afford to hold firm capacity. They need to have backup fuel capability for peak periods when capacity release may not be available or may be expensive. They have limited value for meeting loads on a sustained basis, during a low water year for example, because their emissions permits on typically only for 10 days operation on fuel oil a year This discussion concluded with the suggestion that we should assume for costing purposes that simple-cycle units operate with backup fuel oil or firm transportation in the winter and release capacity in the summer. In addition, we should assume that the commodity prices vary seasonally.

The draft forecast assumed that interruptible local distribution company transportation service would cost $ .18 (2000 dollars per Million Btu). It was stated that very large customers most likely would be operating under a special tariff. Some thought $ .18 was too low, and others though that such costs would not exceed $ .25. There was agreement that large cogeneration projects would have special LDC contracts, no more than 20 - 25 cents. The draft forecast included $ .50 for firm LDC delivery service. There seemed to be little guidance on what this rate should be, but it was suggested that it could be calculated from public records.

Other NG remarks:

Utility and industrial tables should be combined and four delivered price series be tabulated: (1) direct pipeline access; (2) LDC access (Pipeline + LDC transport); (3) LDC supply; and (4) peaking supply.

Other Natural Gas Issues

Morlan asked the committee about recent experience with residential fuel choice for space and water heating. Representatives of local distribution companies stated that nearly all new single-family homes were used natural gas where it is available. Conversions have been running 25 to 50 percent of new home additions, but have slowed with the recession and recent natural gas price increases. The committee wondered how this compared to the predictions in the Council's last power plan.

Oil Prices

With time running short the committee was asked for reactions to the draft world oil price forecast. The general feeling seemed to be that the medium forecast of $22 dollars per barrel was about right Twenty dollars was noted as being consistent with forward price curves. One representative suggested a $3 downside and a $6 to $7 upside range over the next 5 years or so, with the extremes not holding for more than 6 - 7 months. Another member noted that the oil industry, like natural gas and most other commodities, has seen a sustained period of under investment in its infrastructure. This is likely to lead to periods of extreme volatility, with prices varying from $15 to $17 at the low end to the $45 to $50 range over the next five years, but not sustaining prices greater than $30 for periods exceeding a year. One member suggested beginning at $20 and running out to $24.

The remainder of the agenda was not reached at today's meeting. Morlan asked instead that NGAC members send in their comments in written form, call, or email with guidance on these issues.

The second meeting of the NGAC was set for Friday, April 12.

These minutes are an accurate and complete summary of the matters discussed and conclusions reached at the Natural Gas Advisory Committee meeting held on February 28, 2002.

Certified by: _____
Terry H. Morlan, Chairman

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