June 7, 2013

Meeting Time: 8:30 a.m. to 12:30 p.m.

Meeting Location: Northwest Power and Conservation Council
851 SW 6th Ave.
Suite 1100, Public Meeting Room 1
Portland, OR 97204

Facilitator: Massoud Jourabchi, Northwest Power and Conservation Council

Note Taker: Kyle Gustafson

Attendees: Massoud Jourabchi, Manager of Economic Analysis, Northwest Power and Conservation Council
Randy Friedman, Director of Gas Supply, Northwest Natural Gas
Steve Harper, Director of Gas Supply, Avista
David White, Director of Business Development, TransCanada Pipelines
Bill Dickens, Senior Economist, Tacoma Power
Greg Nothstein, Washington Energy Office
Fred Heutte, Northwest Energy Coalition
Byron Defenbach, Manager of Energy Utilization, Intermountain Gas
Lynn Dahlberg, Director of Marketing, Williams-Northwest Pipeline
Rick Harper, Principal Energy Solutions Advisors (Houston, TX)
Ben Hemson, Northwest Gas Association
Jay Jacobson, Resource Planning Group, Puget Sound Energy
Terry Morlan, private citizen
Mark Sellers-Vaughn, Manager of Resource Planning, Northwest Natural Gas
Kelly Irvine, Manager of Gas Planning, Avista
Ed Finklea, Executive Director, Northwest Industrial Gas Users
Michael Cocks, Bonneville Power Administration
Gail Hammer, Bonneville Power Administration
Robert Kennedy, California Energy Commission
Leon Brathwaite, California Energy Commission
Amanda Rosemeyer Greenfield, Cascade Natural Gas
Mike Hopkins, FortisBC
David Hawk, Energy Analysis and Answers
Dan Kirschner, Northwest Gas Association
Steve Simmons, Northwest Power and Conservation Council
Jason Klotz, Northwest Energy Efficiency Alliance
Sam Van Vactor, Economic Insight, Inc.
Clay Riding, Puget Sound Energy
Michael Schilmoeller, Northwest Power and Conservation Council
Tony Liu, Market and Price Risk Analyst, Fortis BC

Meeting Opening: Long-Term Natural Gas Price Forecast

Facilitator: Massoud Jourabchi, Northwest Power and Conservation Council

Massoud Jourabchi called the meeting to order at 9:00 a.m. with a joke about the simplicity of estimating the prices for natural gas, coal and oil. He commented on having a good advisory committee that helps him with this task and thanked the meeting participants for their attendance.

Jourabchi let the group know that they have a full meeting agenda with condensed information. Because the meeting was recorded, Jourabchi asked everyone to speak into the microphone.

Jourabchi let everyone know that he was going to review the draft agenda in the event of any additions or omissions. He shared that the point of the agenda is to let others know about what happens with the data after Jourabchi and his team receive it. After Jourabchi reviewed the draft agenda, Robert Kennedy stated that he and his colleague, Leon Brathwaite, want to make a small adjustment. Kennedy's presentation is the fourth item on the agenda, but he'd like to do his presentation before Brathwaite's, which is third on the agenda, so the information from the California Energy Commission flows more logically. There were no objections to the request. No further changes were made to the agenda.

The meeting attendees introduced themselves. Some of the attendees participated in the meeting via Web conference, including Robert Kennedy, Leon Brathwaite, Amanda Rosemeyer and Mike Hopkins.

Council's Power Planning Process (Slide 3)

Presenter: Massoud Jourabchi, Northwest Power and Conservation Council

Jourabchi began the first presentation on the agenda with a "50,000-foot overview of the Council's planning process and how the natural gas prices feed into (their) work." Jourabchi referred to the "Council's Power Planning Process" slide, which shows the "information flow" and demonstrates the fuel price forecasting process as it feeds into the Demand Forecasting System, from Henry Hub prices to retail prices. Jourabchi explained that Henry Hub prices feed into the wholesale prices of electricity. The Council takes the Henry Hub price to a burner-tip price, an area that Council staff member Steve Simmons works in, and tries to determine the wholesale price of natural gas.

How HH Price Forecast is Used (Slide 4)

Jourabchi shared that the Council also provides the price of fuel to the Supply and Demand Balance Model, a regional portfolio model, where they look at the number of different "futures," and introduce uncertainty (risk and volatility) into the data. The Council uses the prices in the Demand Forecast to determine the retail price of natural gas. Jourabchi stated that the Council also includes the prices of natural gas, coal and oil to determine the wholesale price of electricity, which it uses in the Resource Portfolio Selection.

Relationship between Retail Natural Gas Prices and Henry Hub Prices (slide 5)

Jourabchi referred to a graph on the respective slide that shows the Henry Hub prices (in blue bars) and the retail prices for natural gas for Idaho within different sectors: commercial, industrial and residential. The graph dates back to 1991 and demonstrates similar behaviors between the wholesale and retail prices, with the exception of regulatory lags. Jourabchi explained that the Council econometrically determines type of relationships between the retail and wholesale prices to come up with the retail price, which gets fed into the Demand Forecast.

Comparison of Forecast and Actual 2012 (2012$) (slide 6)

Jourabchi congratulated the committee members for the forecast that they completed last year. In the slide "Comparison of Forecast and Actual 2012 (2012$)," the graph shows that the Henry Hub price natural gas forecast was between $2.40 and $2.70, and the actual price was $2.66. Jourabchi stated that "the reality is cooperating with the forecasters in this case." In the second column, "PRB Coal Prices 2012$/mmbtu," the graph shows that the prices were in the "Medium-Low" range, with the forecasted range between $0.70 and $0.84. The actual price was $0.78.

Participants asked if the $0.78 figure is actually below the "Low" range in the graph. Jourabchi replied, "That's a good question," and recounted the story of the "Persian flaw":

> In Persia, the people make beautiful rugs. Purposefully, one knot in the rug is left imperfect. The people leave the "imperfection" in the carpets because they believe that the only thing that's perfect is God. Therefore, everything else has to be imperfect.

To make sure that this idea of imperfection remained true, Jourabchi joked that he included an imperfection in the presentation.

Regarding the oil prices in the third column of the graph, "Refiners Acquisition Cost Forecast 2012$/Barrel," Jourabchi shared that the forecast ranged between $85 and $105, but the actual price was $101. Jourabchi stated that "the goal isn't to come up with an exact forecast." Instead, the goal is to come up with a forecast that has a "reasonable range."

Jourabchi reviewed how the Council uses natural gas data and invited Ben Hemson with the Northwest Gas Association to do a presentation about the outlook of natural gas for the next 10 years or so.

2013 NWGA Outlook Overview

Presenter: Ben Hemson, Northwest Gas Association

Ben Hemson began his presentation by explaining that the Northwest Gas Association's outlook is an aggregation of publically available data. The data includes member IRPs, the Power Council price forecast, EIA (U.S. Energy Information Administration) and NEB (National Energy Board) data. Hemson shared that he has 10 slides that the meeting participants may have seen in past presentations.

Supply

Hemson shared that there are only a couple of slides about supply because the topic has been covered so well, like in the previous day's conference when someone from BP did a presentation. Hemson encouraged the meeting's participants to attend next year's conference.

BC Production Forecast (slide 10)

Hemson explained that the region depends on two supply basins: Western Canadian Sedimentary Basin (the full blue line in the respective graph) paired with BC production (solid black line in the graph) and the Alberta production from the Canadian supply basin. The Northwest Gas Association sees an increase in production as "BC keeps...pushing up total supply." Hemson noted that there's plenty of gas coming from Canada in the future.

Rockies Production Forecast (slide 11)

In regards to the "Rockies Production Forecast," Hemson stated that the data "shared a story that's similar to Canada's." Kinder Morgan's forecast shows that production is expected to keep increasing, according to the EIA 2013 Annual Energy Outlook. Therefore, there is plenty of gas from both of the supply basins, providing good "optionality."

Rockies Rig Productivity (slide 12)

Hemson told the group that a member from Kinder Morgan gave the Northwest Gas Association a Rockies Supply Outlook presentation earlier in the year. He learned that even though rig counts dropped over the last couple of years, there is a greater efficiency from the current rigs in operation because they produce more natural gas and drill more wells. Even though there are less rigs, gas production hasn't dropped as quickly as one might expect. Hemson commented that this information is good news for local consumers.

Demand

Recent Gas Demand (slide 14)

Hemson pointed out in the "Recent Gas Demand" slide that the commercial and residential demand loads have been "pretty steady and stable over the last 10 years and beyond." In spite of the recent recession, there hasn't been a big increase or decrease in demand.

Hemson highlighted that industrial loads (maroon/magenta bar in the respective graph) experienced a "big hit" in the early 2000s because of the Western Energy Crisis. However, since the "Great Recession," the "big story" has been about reduced energy loads due to the disappearance of wood and paper from the region. Hemson explained that "we're losing the 24/7 really great gas loads that utilities and pipe lines love so much. I mean, that's what's really easy to plan, easy to build on. Good loads." He pointed out that new generation loads are replacing or becoming an addition to/coming online with traditional loads. Companies are trading out steady loads for weather-dependent, water-variable loads.

Dan Kirschner with the Northwest Gas Association asserted that when there's a "high-water year, there's not a lot of gas deman, like in 2011." He explained that when there was a low-water year, like in

2008 and 2009, the demand for gas was higher, making it more “volatile” on a annual, monthly and daily scale, which makes planning harder.

2013 Outlook Demand Forecast (slide 15)

Hemson shared that the respective slide was a normalized projection for the year 2013.

At this time, Jourabchi ask if the PNW shows the “four states plus Canada,” or if it includes Utah and Wyoming. Hemson answered that it includes Oregon, Washington, Idaho and the province of British Columbia, Canada.

David White then asked about the orange Power Consumption line in the “Recent Gas Demand Slide.” Hemson shared that it represents end-use power consumption in the region. The line gives a sense of scale when one compares end-use gas use (the bottom three bars on the graph) to power. He concluded that the orange line shows that on an end-use type of scale, gas use in the region is almost on par with power consumption.

Randy Friedman asked Hemson if the measurement on the “Recent Gas Demand” graph was a conversion of kilowatt hours. Hemson said that it was, and David Hawk shared that there's a specific formula used to determine the conversion. Hemson said that when his company does community outreach, they tell people that gas use is "on par" with power, as gas is a significant energy source in the region.

Kirschner shared that in 2012, electrical demand grew faster than gas demand. Jourabchi stated that this could be due to weather adjustments, which aren't reflected in the respective graphs.

Hawk claimed that the growth in demand in 2012 was due to the air conditioning load. Jourabchi said that the demand was also due to industrial demand for electricity, which is picking up.

Steve Harper commented on server farms. Then Clay Riding expanded on Harper’s comment by talking about power consumption in Oregon, Washington, Idaho and Vancouver B.C.

Jourabchi said that the Council will look for the 2012 load data, which FERC (Federal Energy Regulatory Commission) will release in the next few weeks. When the data becomes available, the Council can review the impact of temperatures and make a report about it in the next few months. Jourabchi explained that the consumption referred to is “consumer consumption” and that "load" refers to the generators, so the T&D losses aren’t included.

2013 Outlook Demand Forecast (slide 15)

After bringing up the respective slide, Hemson explained that the graph isn't broken down by end-use. Instead, it represents the total demand in the region. The dashed line represents 2008 by million decatherms. The solid purple line refers to the Base Case in 2013, which shows a 15 percent decline, representing resources that left the region or are no longer consumed. The same scenario goes for the Low Case line on the graph. Hemson pointed out that there's a jump in the 2013 High Case, reflecting generation in residential and commercial loads.

Hemson stated that the difference in the industrial load High Case and Low Case lines is 0.2 percent; not a big difference. He claimed that, currently, there is no prediction about an "industrial renaissance" from using natural gas. However, some recent IRPs show that High Loads include the potential for an increase in the industrial loads going forward.

Jourabchi asked if the graph includes power generation. Hemson said that it does; it includes total demand.

Forecast Comparison by End Use (slide 16)

Hemson explained that the respective slide is the current projection going forward, which includes the 2008 projections. The graph shows a decline, with industrial loads experiencing the biggest drop at about 15 percent. Generation loads was also down because the recession caused power demand to decline.

Hawk asked if the 2008 base represents the "actual" figures, where it intersects at the X-axis. Hemson said that he assumed so. Kirschner stated that all the figures, except those for 2013, are actual figures.

Robert Kennedy then asked about what contributed to the climb in demand. Hemson said that it's attributed it to the recession, especially when it came to industrial loads. He explained that wood and paper products experienced a big loss in the region. There were slight reductions in residential and commercial demands, as well. "On the power side," Hemson observed, "Looking forward from the base cases in 2008 and 2013, there's a big drop in generation demand as well because of the recession."

Hawk commented that the prices of 2006 through 2008 prompted people to start looking more into conservation in regards to gas and, in particular, electricity. Hemson said that there's a "confluence" of factors that could have influenced the reductions, but the recession is the main culprit.

Jourabchi asked if there was a forecast for the power sector in the earlier years. Hemson replied that there is, but he forgot to add the line to the graph.

Hemson continued, stating that there is a PGE base-load 400 megawatt plant in the IRP. The NWGA made some assumptions about heat rate and utilization rate, resulting in a big jump in generation.

Friedman asked if the Boardman Coal Plant was taken into account for 2020. Hemson said that it was not because it isn't currently in the IRP; the same goes for Centralia. The NWGA relies on the IRP data. Kirschner explained that, going forward, they are considering determining different scenarios with assumptions about what may happen if the two plants are replaced.

Jourabchi said that the Council is thinking about having more information on the gas side in the Seventh Plan and thinking of bringing in the "numbers" about gas generation from the Aurora Model to provide more information for the region, which would include the retirements of some of the coal plants and other plants.

Terry Morlan wanted to clarify if, in regard to the drop shown in the old and new forecasts, the NWGA "expected it to stay down in the future and just continue to grow," which would result in a permanent loss of industry. He also asked, "Is this the pulp and paper industry?" Hemson said it is the paper and pulp industry. According to the forecast, the industry is gone, but it may come back.

Kirschner said that they focused on the “data (they) have and the data (they) know,” so it's hard to “figure things like gas replacement because it's not being planned for yet.” He explained that this year's outlook doesn't replace the level of activity that their members are experiencing on the industrial consumption side since no deals were cut and no commercial agreements were signed, thus the reason the data doesn’t appear.

Ed Finklea stated that from the industrial side, some industry is starting to come back, even in pulp and paper. He reflected that there was some “permanent demand destruction” during the recession in 2007 and 2008, like at the Blue Heron plant, for example. He stated, “If you drive down I-5 to Albany, where the old Willamette Industries was, you'll see that it's gone; like what the region went through in 2001 and 2002 when they lost aluminum smelters. If some markets pick up, like the housing market, other industries will follow, like the timber market.”

Hemson agreed that if the economy did turn around and industrial loads picked up, there would a big jump in the future because of the data that they take into account as IRPs become available, like the plans for the Boardman and Centralia plants.

Hawk asked if a bio-mass plant is still planned. Lynn Dahlberg with the Williams Northwest Pipeline replied that it is still planned. White then shared, "They are conducting a pilot project to grow arundo, which is a giant cane. They will make it into charcoal briquettes-like, pulverize it and run it through the existing pull boilers. And, that plan is still on track. They're growing a whole bunch of it. They've harvested it, I think, a couple of times, now. But, they have yet to run the test to see how it burns and what it yields."

Hawk then asked if the uncertainty about the success of arundo is the reason that “they're going to go with the 400 megawatts.” White responded that the 400 megawatts was identified as a resource requirement under their IRP to serve growth. He stated that they haven't announced a replacement for the coal plant except to do the arundo pilot study. White thinks the first test-firing is in 2014 or 2015.

Kirschner shared that the 2008 forecast line in the graph that represents power generation includes Puget's IRP "generic" 500 megawatt generation. He explained that the dropped off in the latest two IRPs showed a 2,000 or 3,000 megawatt of capacity by 2020, but no additional gas-fired energy in its capacity. Kirschner said that the graph takes into account PGE's latest 440 announcement, “which makes up for the big jump.” He continued, “This wasn't in place four years ago when we did the 2008 outlook. The curves look similar because they have a based load plant in each of these forecasts.”

Fred Heutte said that the PGE plant is a 200-megawatt second unit at Port Westward, which is now a peaker plant. Hemson explained that the plant in the graph reflects a different plant. Heutte then said that he's confused about what the jump in 2016 represents. Hawk said that it reflected the plant that PGE announced the previous day, June 6, 2013. Kirschner added that this plant is a "placeholder" because they don't have a spot on the map yet, but he thinks that it does reflect the plant that PGE announced.

Heutte stated that the Port Westward II plant could also contribute to the increase. He also said that there are other proposed plants in Oregon. For example, aA plant in Troutdale proposed a 600 megawatt plant. The Perennial Company is proposing a 400 megawatt plant that they call the "Wind Chaser." Huette shared that there was also a recent filing for the South Dunes Plant, which would “fee” an LNG export terminal in Coos Bay. He also speculated that there may be an increase in gas demand in the mid-to late-decade. Hemson said that the NGWA would use this type of data in a scenario analysis because it's not in an IRP.

Hawk shared that there's a proposal for a market facility in Idaho that's up to 1,000 megawatts, along with discussion of a fertilizer plant that will use a "fair amount" of natural gas.

Riding commented that if the data considers every plant proposed, "the numbers would be off the chart." He provides examples of the proposed plants that he would and would not include in the figures.

Hawk then discussed sending power to California because it doesn’t have any new plants and some recently shut down. He added that California will have to look to out-of-state resources for its power.

I-5 Peak Day Demand-Resource Balance (slide 17)

Hemson directs the group to the slide with a graph showing the end results, which highlights future peak-day demand, which is about 1 million decatherms a day. The graph shows how demand affects the amount of gas that they deliver on the coldest days of the year.

In response to Heutte's question about the graph, Hemson explained that there are more pipelines east of the Cascades.

Capacity Projects (slide 18)

Hemson reviewed the capacity projects in 2008, which included pipelines, LNG terminals and storage facilities.

NWGA Members (slide 19)

Hemson shared that there is a lot of potential for the LNG facilities in Vancouver B.C., stating that the market is good about responding to regional issues. For example, environmental and pre-construction consultants have reached out to Hemson and Kirschner about gas for transportation, industrial loads and other concerns to learn more about energy.

North American Market Gas-Trade (NAMGas) Model: Updated Common Cases

Presenter: Robert Kennedy with the California Energy Commission

Work Continuing with Cases (slide 22)

Robert Kennedy began his presentation that by stating that he works with the Natural Gas Unit at the California Energy Commission (CEC), which mandated by law to produce an integrated policy report every two years. To complete the modeling process, the CEC looks into market trends, which feeds into an integrated energy policy. Kennedy shared that the modeling process is an open process where stakeholders can have an active role.

Kennedy stated that his presentation is one that he previously provided at an Integrated Energy Policy (IEPR) Workshop on February 19, 2013. Participants had the chance to see the CEC's preliminary results and the iterative modeling process.

Kim Medlock from Rice University, Kennedy shared, provided the CEC with the North American Gas Trade Model. The model begins with demand input data, which the CEC receives using historical data and historical sources, like the EIA. The data goes into an econometric model to generate future demand inputs, which feeds into the North American Gas Model. When the CEC ran the model, it produced initial outputs that fed into the Gas Demand Model that, Kennedy believes, also produced natural gas prices. The CEC also fed the data into the Production Cost Model, in which the CEC had to apply some more calculations to produce burner-tip prices. The team also applied transportation prices to the Natural Gas Model.

To complete the Demand Model, the CEC obtained information about the demand of natural gas from the commercial, industrial and residential sectors. Kennedy stated that the Production Cost Model helped the CEC learn about the demand for natural gas from the power generation sector. From the Transportation Demand Model, the CEC learns about the demand for natural gas for transportation vehicles.

Reference Case: Changes Made from February 19th Assumptions (slide 23)

Kennedy told the advisory committee that CEC posts all of its results online, as well as the workshops at the IEPR proceedings on February 19, 2013, the recorded WebEx presentations and MS Excel files that outline the assumptions that the CEC fed into their cases for the Interactive Modeling Process.

Kennedy explained that the respective slide shows changes that the CEC made since the February 19, 2013 workshop. He said that he presented information in the April 24, 2013 workshop and there is a change in the Coal Fire Generation Retirement assumption. Initially, the CEC started with a 30 gigawatt retirement starting in 2014, but the CEC changed this to a 61 gigawatt retirement starting in 2014. Kennedy asked the advisory committee to keep in mind that these figures are for the CEC's Reference Case, which they received from the Brattle Group, who released an updated report in October 2012. Kennedy noted that the CEC also adjusted its results according to the Renewable Portfolio Standard.

Initially, the CEC had California meeting the RPS on time with a five-year delay for other states. The current data now reflects all the WECC states meeting the RPS requirements on time, but the states outside of the WECC have a five-year delay.

According to Kennedy, the new developments in Mexico increase the demand for natural gas. Since a lot of projects exported natural gas to Mexico, the CEC updated the infrastructure data in its model.

From its previous hyper-cycle, Kennedy shared, the CEC went from a World Gas Trade Model to its current model, which focuses on a North American Gas Trade Model. He stated that the CEC made a "note that represents the rest of the world, which is an LNG note that accounts for all imports and exports to North America," which resulted in some adjustments to the CEC's data.

High Price/Low Demand Case: Changes Made from February 19th Assumptions (slide 24)

In regards to High Price/Low Demand Case, Kennedy shared that changes include those related to the cost environment and the LNG in Mexico.

Low Price/High Demand Case: Changes Made from February 19th Assumptions (slide 25)

In the Low Price/High Demand case, Kennedy said that the CEC modified some assumptions. It adjusted the cost environment so steel and other materials are less expensive to obtain.

North American Market Gas Trade Model: Developing a Cost Environment (slide 26)

Kennedy explained that the respective graph uses the historical information that the CEC received in the past in regards to cost environments. The blue line represents the high cost environment, which the CEC applied to the High Price/ Low Demand Case. The red line represents the low cost environment, which the CEC applied to the Low Price/High Demand Case. Initially, the natural gas demand forecast calculations produced a narrow range, so the CEC added information about the high and low cost environments to widen the range

Performance of Cases: Lower 48

Common Cases: Price Performance of Cases (Henry Hub) (slide 28)

When the respective slide appeared, Kennedy asked the advisory committee to keep in mind that the CEC's work is ongoing, so it may adjust the data in the future.

Kennedy stated that on the respective slide, the dotted line on the graph represents the price forecast that the CEC produced for the February 2013 workshop. The solid line represents the data from the April 2013 workshop. Kennedy shared that the CEC's stakeholders commented on the range being too narrow. In the past, the CEC had a wider band, to take into account the effect of the production of shale. With the wealth of supply, Kennedy explained, there is a lot of data that can add to uncertainty. A big surge in shale production adds a lot to that uncertainty, which the CEC represents in the "narrowness" in its forecast.

Hawk commented that data on the graph shows the average annual price for each of the cases because there may be month-to-month spikes and dips. Kennedy affirmed this comment, stating that the model does show the average annual price. In the future, the CEC is going to adjust the model so it represents monthly figures that capture the seasonal variations in prices.

National Cases: Price Performance of Cases (Differentials) (slide 29)

Kennedy explained that the graph on the respective slide shows pricing differentials between Topock and Henry Hub. Initially, the CEC started with negative figures in 2011 and 2012. Kennedy noted that since then, "the Topock tends to go higher versus the Henry Hub;" this trend is true for all the preliminary High, Reference and Low Cases. Kennedy suggested that the trend may be due to the increased production of shale, particularly on the East Coast, where they're closer to the production region.

Bill Dickens asked Kennedy if the CEC has the data for the Sumas-Henry Hub differential. Brathwaite, who is with the CEC, replied that they do have the data, but not in graph form. Dickens said that he would like the information emailed to him. Jourabchi reminded the advisory committee that everyone's email address is on the member's list. Kennedy then asked Dickens to send him a detailed email about the exact information that he seeks because he keeps records of all the information requests received.

White then asked Kennedy to explain the assumptions behind the High Case in 2020. Kennedy shared that the CEC sets the assumptions so it forces the capacity for LNG expansions, which drives up demand. Natural gas in the form of LNG is exported. He stated that because this isn't a "normal" market, the CEC forces this type of data into the model to reduce the "strange' outputs. Brathwaite commented that he doesn't know what particular data caused the change that White refers to, but he can look into it and get back to him.

Riding said that if the data assumed that LNG rose in the Gulf Coast in 2020, it may raise Henry Hub prices relative to Topock. Kennedy reminded him that in the High Case, the CEC accounted for "more coal conversion going on, which basically drove up demand for natural gas, made it more scarce and essentially affected the price upwards… So, that could be another factor."

Common Scenarios Cases: Supply Portfolio of Reference Case (2025) (slide 30)

Kennedy shared that the respective slide shows a "snapshot" of the year 2025 on a national level. The CEC calculated 13.3 Canadian imports, 8.2 exports to other countries and 0.24 LNG imports. The net result of this activity is about 5.3 Bcf per day coming into the U.S. in 2025. Kennedy admits that other groups feel differently about this data and thinks that by the year 2020, the U.S. will be a net exporter of natural gas—of pipeline exports and LNG exports combined. He told the advisory committee that the CEC would value their input about where they see the U.S. in regards to imports and exports, asking, “Where you see the U.S. headed in the next 15 years?”

Kennedy stated that the CEC looked at its model to see why it's producing the current results. He pointed out that rate of production increase in Canada is significant and much greater than what the CEC saw "out of (its) model for the lower 48 (states). Granted, the overall magnitude of the number is less than the lower 48, but (in regards to) the rate of the production increase, we did see a big takeoff." Kennedy stated that the CEC also saw competition between GTN and Ruby, so the model produced results that showed a "greater flow on GTN versus Ruby." He then told the committee that the CEC is interested in receiving feedback about these results. Kennedy asked, "Do they seem reasonable or not? If you anticipate or see some other activity that may happen, the CEC is interested in hearing about it."

Hawk told Kennedy that he doesn't think that the rate means anything of significance because it's a "function of resource capability and a lack of optimism." In his opinion, the number that CEC has for "Production: 75 Bcf" is the more important figure because it relates to storage capability and demand.

Friedman asked Kennedy about the 2025 Reference Case slide: "Is this supposed to balance?" Brathwaite responded by explaining that there are two main demands: end-use and exports. Reading off the slide, Brathwaite continued, "The demand is satisfied by: Canadian imports, LNG imports and lower 48 production." Brathwaite then asked Friedman what he meant by "balance." Members of the advisory committee pointed out that the "imports, plus production, are less than the demand, plus exports," adding that the charts don't show exports into Canada and Mexico.

Brathwaite explained that the supply should be greater than the demand because there are between 3 to 7 percent losses: "Between a production facility, between the point where gas is produced and where it is consumed, there are losses." He shared that the model considers losses on the compressor and losses that are unaccounted for, for example, so supply won't equal demand. Instead, supply is greater than demand.

In regards to the slide about lower 48 production versus demand, Friedman said that it looks like the CEC needs a little over 2 Bcf per day of imports to satisfy the demand. He explained that he sees on the slide that there are 13.5 Bcf per day between imports from Canada and LNG imports, minus 8 Bcf per day of exports, leaving "5 net of imports." Therefore, there is 3 Bcf per day unaccounted. Friedman asked, "Are these losses?" Brathwaite said that they are not losses because there are 8.2 Bcf per day going outside the U.S.

Hawk commented to Brathwaite, "You have 80 production, plus imports, versus a demand of 77."

Mike Hopkins added that production plus the net imports come out to about 80 Bcf per day. When compared to demand, about 77 Bcf per day, one is left with about 3 Bcf per day that's unaccounted for. Members of the advisory committee suggested that the losses seem too high.

Kennedy assured the committee that the CEC will take the losses into account. He then asked if the pipeline and LNG net imports seem reasonable to the group.

Brathwaite interrupted, saying that he calculated a 4 percent difference in the figures. Kennedy and Brathwaite both explained that that the export number includes an aggregate of pipeline and LNG; the Canadian number of imports is a gross figure.

Common Scenarios: Reconfiguration of Supply Portfolio (2025), High Price/Low Demand Case (slide 31)

Kennedy told the group that the current slide shows the comparison of the High Price/Low Demand Case versus the Reference Case. He explained that the end-use lowered by 8.2 percent and exports went up by 61 percent. The CEC forced LNG exports in the High Price Case, which resulted in increases in exports versus the Reference Case.

Common Cases: Reconfiguration of Supply Portfolio (2025), Low Price/High Demand Case (slide 32)

Kennedy stated that in regards to the Low Price/High Demand Case versus the Reference Case, there was a price decrease of 16.2 percent. He said that end-use responded to the lower prices, making it increase by 8 percent. Exports declined by 36.5 percent.

Performance of Cases: California

Common Cases: Price Performance of Cases (Topock Hub) (slide 33)

Kennedy explained the respective graph to the advisory committee, stating that the dotted line represents the initial price forecast and the solid lines represent the current updated data for the price forecast. He commented that the graph shows a narrow range.

Common Cases: California Supply Portfolio (2025), Reference Case (slide 34)

Kennedy highlights that the respective graph shows the Reference Case with the 2025 imports coming in at Malin at 2.67 Bcf per day, 1.22 Bcf per day at Rocky Mountain and 2.3 Bcf per day at Southwest.

Common Cases: California Supply Portfolio (2025), High Price/Low Demand Case (slide 35)

For the respective slide, Kennedy explained that in the High Price/Low Demand Case for 2025, the price increases by 16.7 percent versus the Record Case specifically for the state of California.

Common Cases: California Supply Portfolio (2025), Low Price/High Demand Case (slide 36)

Kennedy quickly reviewed the respective and reminded the group that the CEC's work is ongoing and the next workshop is on July 17, 2013; everyone in the advisory committee is invited to participate. The workshop will be available via WebEx. Kennedy then reiterated that the CEC stakeholders are concerned with the "large zone of uncertainty" and that the organization is working to address that.

Hawk asked Kennedy in regards to retirement of coal generation in 2014, how the CEC plans to replace it. Brathwaite stated that natural gas will replace it. Hawk observed that the use of natural gas isn't reflected in the data that Kennedy provided. Kennedy said that Hawk is referring to the Low Price/High Demand case. Brathwaite interjects, stating that he doesn't understand the question. As Kennedy attempts to explain Hawk's question, White explained Hawk's question: "Is the 31 gigawatts of coal replacement, assuming it's all replaced with gas, reflected in the new demand numbers on your subsequent slides?"

Brathwaite stated that, yes, natural gas will replace the coal. Hawk said that it seems like it's going to take "more than a couple hundred million feet of gas a day" to replace 31 gigawatts of coal. Brathwaite then asked Hawk where he derived the "couple hundred million" figure.

Kennedy explained that, in regards to the reference case, the end-use demand increased by 8 percent. The demand was satisfied by a 5 percent increase in lower 48 production. Brathwaite then stated that it's important to remember that there are "other things going on in the market at the same time." He shared that the CEC factors in occurrences that may happen in the market when developing the models. Kennedy added that the 31 gigawatts of retirement in the Low Price/High Demand Case enter 61 gigawatts of retirement in the Reference Case. Therefore, there is more demand for natural gas in the CEC's Reference Case.

Hawk argued that the energy can't all be from natural gas because the slide shows that WECC meets its RPS standard, which brings renewable resources online.

Riding adds that the group may be assuming that coal plants are base-load plants, which isn't a good assumption to make. So, there's really no need to dwell on these assumptions. The group agrees.

White asked for the date of the next CEC workshop. Brathwaite told him that it's on July 17, 2013. Bill Dickens inquires if the model will reflect the retirement of SONGS and its impact on natural gas demand. Brathwaite told Dickens that he needs to look into this.

Finklea asked that since production in California is at 0.21 in the slides, if the CEC assumed that shale is not developed by 2021. Brathwaite said that, yes, the CEC was making this assumption.

Jay Jacobsen then asked if the CEC will include more than the High Demand/Low Price and the other case referred to in the slides for its scenarios. Brathwaite shared that the CEC is presently examining 10 cases, and that he is going to make a presentation about some of the cases momentarily.

Hawk shared that in California, there's a question about the Monterey formation's ability to sustain development. He said that it's more liquids-rich than other shale plays, but its economic viability is in question. Brathwaite commented that the CEC doesn't expect this to have big impact on natural gas.

Shale Production Uncertainty Cases: A Scenario Examination

Leon D. Brathwaite, California Energy Commission

Brief Background (slide 41)

Leon Brathwaite gets right to the first slide at the beginning of his presentation, stating that shale development is transforming the natural gas market. Consequently, controversy has followed. He explained that the controversy comes from the potential for groundwater contamination, possible increases in seismic activities, diverting the fresh water used in hydraulic fracturing and the possibility of added methane emissions.

Brathwaite shared that decision-makers are taking steps to mitigate some of the risks that shale development can pose. For example, some jurisdictions in New York delayed the development of its shale resources. Some areas have implemented environmental impact fees and others, like in California, tightened hydraulic fracturing regulations.

Brathwaite noted that technological innovation is ongoing and has accelerated the natural gas industry with the introduction of horizontal drilling and hydraulic fracturing, thus impacting the market. As a result, the production of shale is rapidly on the rise. Brathwaite provides the following example: in April 2013, shale formations produced 30.6 Bcf per day. Incidentally, shale production represents about 40 percent of the market share.

What are the Shale Production Uncertainty Cases? (slides 42-43)

As shale transforms the natural gas market, Brathwaite shared, the CEC examines the impact of the shale in a handful of scenarios: “shale abundance,” “shale reconsideration,” “shale expensive” and “shale deferment.” He iterates that these scenarios are *possible*, not *plausible*. The CEC is just trying to answer the question, “What if?”

Key Variables (slide 44)

In the model that the CEC uses, Brathwaite explained, it looks at four key variables, which are changes in: supply cost curves, time of availability of some resources, environmental impact fees and the rate of technological growth and innovation. Brathwaite stated that all the changes assessed remain relative to the reference case. However, the CEC may make minor changes to a Reference Case as appropriate.

Shale Abundance (slide 45)

When considering the abundance of shale, Brathwaite explained that the CEC begins with the Reference Case. It then considered cost curve changes, which include an expanded resource base and the development of all known shale formations. He stated that “current estimates are 15 percent low, which lead to the upward adjustments of curves.” In regards to availability changes, there are no delays in production hookups. Brathwaite shared that the environmental impact fees and water handling cost changes are at the low end of the range at $0.30 for every thousand cubic feet (Mcf). Technological growth change is at 2.5 percent, a rapid rate.

Shale Reconsidered (slide 46)

After reviewing the Reference Case, Brathwaite stated that the CEC moves on to the supply cost curves in “Shale Reconsidered.” He shares that there are concerns about delays in hydraulic fracturing, which can impact the further development of shale formations. He explained that there is also a “targeted moratorium” on new drilling and new formations, and that the resource base is shrinking by 15 percent.

In regards to production hookups changes, Brathwaite noted that there are significant environmental challenges that delay new production by about three years. Consequently, impact fees and water handling cost changes are at the high end of the range at $0.55 per Mcf. Technology in this area has a growth rate of about 1 percent.

Shale Expensive (slide 47)

As with the other scenarios, Brathwaite stated that the examination of "Shale Expensive" begins with the Reference Case. Analysis of the supply cost curves follows with little change from the Resource Base to the Reference Case. Changes in new production hookups face significant environmental challenges because delays can run about three years. Brathwaite noted that many jurisdictions face environmental impact fees that are 20 percent greater than the high-end cost, amounting to $0.67 per Mcf. The growth of technology slows down to a rate of 0.5 percent, which is half of the Reference Case.

Shale Deferred (slide 48)

After examining the Reference Case, Brathwaite said that one moves on to the supply cost curves next. Again, the resource base remains unchanged from the Reference Case. As with "Shale Expensive," "Shale Deferred" experiences environmental challenges, as well as challenges in the hookup of new production, with delays running between three to five years. Changes on impact fees and water handling costs, which make up a large portion of the expenses, are at the high end of the range at $0.55 per Mcf. Brathwaite stated that technology experiences improved growth in this area at 1 percent.

Brathwaite shared that the CEC is in the process of developing the shale-related cases. He expects results to be available at the July 17, 2013 workshop.

Jourabchi asked if the scenarios relate to shale in the United Stated or if they include Canada and other parts of the world. Brathwaite replied that they relate to the shale in the U.S. and Canada. Jourabchi then asked the advisory committee if they think that the assumptions presented seem reasonable, inviting their comments.

Hawk commented that one thing that the industry is experiencing gains in efficiency in regards to single well pads and the number of wells that are drilled. He provided the example of the Pinedale Anticline, which cleared a 17-acre pad and drill 25 wells using one rig. He stated that the plant cut back on the number of trucks and added water pipelines. This is a trend that Hawk said is occurring in many places. While he isn't sure what "growth in technology and innovation" means and how it's priced, Hawk has seen increased growth in shale-related efficiency and operation over the last seven years, as well as a decrease in cost per well and a decrease in the time it takes to drill a well. He said that companies can drill a big well in 18 days instead of 45 days. Hawk thinks that the impact and water handling fees in Brathwaite's scenarios "should be what they are today and given a 3 percent cost escalator."

Rick Harper adds that shale is growing rapidly and that any slow-downs are because of current prices. Harper stated that, "in a broad sense," he hasn't seen delays in production. Instead, he's seen rapid growth and lowered costs. Friedman agrees, but adds that not all shale jurisdictions "are created equal." To him, it seems like technology is increasing at the same rate of new regulations, which may offset any delays.

Brathwaite reiterates that the scenarios are not plausible and the CEC is not claiming that they are possible. It is simply trying to look at the impact of “what if” conditions. Brathwaite stated that he is not implying that any of the scenarios will occur. In regards to Hawk’s comment about efficiency, Brathwaite explained that the supply cost curves are dynamic and the CEC tries to reflect as much efficiency as possible in terms of cost reductions, drilling and production.

Sam Van Vactor cautions that forecasts need to be consistent with oil prices. Brathwaite replied that he understands and that a lot of the gas produced is associated gas. He explained that the CEC tries to take into consideration in its model the fact that the industry’s production of shale comes from the efforts to go after liquid gas.

Jacobsen then asked if the CEC considers CO_2, environmental costs and the effects on the cost of natural gas in its analysis. Brathwaite said that it does, but not in the scenarios that he presented. Brathwaite asked Jacobsen to send him an email requesting this information as he doesn’t have it on hand.

CO_2 Costs

Presenter: Steve Simmons, Northwest Power and Conservation Council

Steve Simmons began his presentation by explaining how the Council looks at the implications of CO_2 on the Electric Price Forecast and Production Cost Model. He stated that the Council has a couple of scenarios for incorporating CO_2 costs, like in wholesale electricity prices or consumer retail rates.

Simmons shared that the Council hasn’t modeled any emissions that may result from power generation as it presently only takes into account coal and natural gas. He explained that CO_2 is “essentially modeled as a tax” and the Council is modeling California’s Cap and Trade program. However, due to model limitations, CO_2 is modeled as a tax, as an attachment to dispatch costs.

Current Assumptions (subject to change) (slide 50)

For the respective slide, Simmons explained that the Y-axis represents dollars per ton of CO_2 and the X-axis is a time horizon of 2013 to 2035. The red dots represent a case where no federal CO_2 policy is enacted. The solid blue line represents a “delayed federal CO_2” case and, Simmons shared, it is the same curve that the Council used in the Sixth Power plan, except deferred for five years. He stated that in the Sixth Plan, the federal case phased-in around 2010. The graph shows a delayed federal case phasing-in at 2015.

Hawk commented about the reality of a CO_2 tax because many plans have been wrong about it. Simmons replied that the models show the value of conducting different scenarios.

The yellow dashed line on the graph, Simmons noted, represents the social cost of CO_2. A greenhouse gas symposium earlier in the week addressed a similar issue. Simmons said that the Interagency Working Group on Social Cost of Carbon estimated the damages of CO_2 emissions, which the Council incorporated like a carbon tax.

Wholesale Price Forecast at Mid C (slide 51)

The respective slide, Simmons stated, showed the most recent Wholesale Price Forecast with wholesale electricity at the mid-C. He shared that the Council's website has a report about this forecast that includes more details. Simmons explained that the graph comes from the Dispatch Model Aurora and the different lines represent the different cases that the Council is examining. The red dotted line represents a "no federal CO_2" case and the graph shows an increase in 2020 because of the Boardman plant retirement. He explained that the coal plant retirements in Boardman and Centralia equal an increased reliance on natural gas, so there's more fuel consumption and potential gas dispatch.

Hawk asked for the conversion of dollars per megawatt hour to dollars per ton of CO_2. Simmons said that the Council could do this.

Simmons noted that some of the factors driving the price of CO_2 correlate with natural gas prices and other factors like "hydro," wind generation, coal retirements, California's once-through cooling plants that are closing, the SONGS plant closures and California's Cap and Trade program.

White asked Simmons about the Council's assumptions regarding the SONGS plant closures. Simmons replied that Council assumes that both plants it will be online again in 2015.

Dickens asked Simmons asked if the Council considered critical water and average water in its assumptions. Simmons replied that the Production Cost Model is all "average." Dickens stated that his organization does a mid-C forecast for both types of water.

Hawk asked if the Council has considered what the change would be if it looked at the last 30-year average. Simmons stated that it has not and that the Council uses the same hydro-related parameters. After Hawk made a comment about how the data changed when looking at a 30-year average, Simmons asked him how it changed. Hawk stated that "it shows less water."

In regards to the graph, Simmons stated that the blue line represents "federal CO_2 in place," showing the capacity for coal plants dropping and a higher level of gas dispatch.

At the end of Simmons' presentation, Hawk commented that if one wants to have an effect on CO_2, they need to start at $60 or $80 per ton. He explained that the "shock effect" encourages change because most consumers don't care if there is a small increase in price.

Heutte shared that he's seen credible analysis that suggested that California's market already reflects the CO_2 price from the AB32 Cap and Trade by about $5 per megawatt hour, which is a 10 percent increase that will be reflected in California's fuel mix. Agreeing with Hawk, Heutte stated that it takes between $75 and $100 per ton to start significantly shifting CCF's effectiveness. Simmons replied that he saw an example of this effect and how it impacted coal at the greenhouse gas symposium: "Modeling indicates that it will have an impact at any price."

Hawk asked Simmons if he thinks there will be federal legislation with a carbon tax, not a cap-and-trade, within the next six years. Simmons replied that he can't even put odds on this assumption. Morlan shared that they are going to get into how the Council uses the assumptions in their portfolio analysis, which offers a more robust look at uncertainty as it looks at the effects of risk on choices. He noted that the risk of carbon taxes is already affecting market behavior, like in the decision to shut downs some of the coal plants, return-on-interest considerations for investment upgrades and government policies, demonstrating that a carbon tax doesn't need to be in place for some of the effects to already take place.

Jourabchi wraps up the first half of the session and dismisses meeting's participants for a 10-minute break.

Strawman Proposal for Preliminary Seventh Plan Forecast of Prices

Presenter: Massoud Jourabchi, Northwest Power and Conservation Council

Background (slide 53)

Jourabchi recommenced the meeting at about 10:50 a.m. He told the advisory committee that he sent a Strawman Proposal to the members in May 2013 and that he'd like to offer a review of the past few years.

Jourabchi shared that when the Council did the Sixth Plan, it expected the short-term prices of natural gas to be higher than they actually were. Consequently, in 2011 and 2012, the Council started "downgrading" and lowering the range of natural gas prices. Jourabchi explained that in the 2012 analysis, the Council lowered the short-term price of gas for the years 2013 and 2014, and made the 2015 prices follow the same "trajectory." Jourabchi stated that he thinking of raising short-term prices and narrowing the forecast range post-2015.

Henry Hub Monthly Prices, Constant 2012 (slide 55)

Jourabchi reviewed the respective slide, sharing that it showed the June 11, 2012 price. He explained that prices were about $2.00 in 2012 and the average price was about $2.60. In the past few months, there has been in increase in prices.

Jourabchi stated that many people expected the prices to stay in the $2.00 range during 2012. However, a year later, in April 2013, prices are in the $4.00 range. Jourabchi explained that the price doubling speaks to the volatility and changes that one sees in the market.

Natural Gas Straw Man Proposal Compared to Short-Term Prices from SNL Annual Strip (as of May 1, 2013) (slide 58)

For the short-term 2013-2014 forecasts, Jourabchi stated that the graph shows data out to the year 2019, but the data that he used stops at 2015. He explained that the SNL projections are based on the actual strips currently available, which go out 2019. He also noted that the projections suggested that the price will stay at about $4.00, from $4.10 to $4.20. The data in the graph shows "constant dollars" without the imbedding of inflation.

Jourabchi stated that for 2013, the Council thought the prices would be in the $3.70 to $4.00 range, which is slightly higher than the 2012 prices. He observed that prices are slowly increasing and not taking into account an abnormally hotter summer or colder winter. He shared that in 2014, the prices will increase by about $0.10 and will stay within the $3.80 to $4.00 range. Jourabchi then asked the group if the short-term assumptions (the high $3.00 range to low $4.00 range) sounded reasonable.

Heutte commented that he thinks that, because shale is expensive, prices will continue to increase slowly. He also thinks that the price increase over the last year was an unusual deviation that had to do with some short-term market factors. Heutte stated that by looking at inventories and, particularly, the increase in exports to Canada and Mexico, one can see the price effects and the industrial demand making a national comeback. He thinks that people will also start to look at natural gas fleets and transportation seriously. Heutte shared that he expects prices to increase over the next two years because the information that he's seen about the marginal cost of shale gas is usually well above the current market. So, while prices won't increase as quickly as they did over the last year, Heutte stated that expects the upward trend to continue over the next year or two.

Jourabchi asked Heutte about the marginal cost numbers that he's seen. Heutte responds that "a lot of it is proprietary," but surveys that he's seen suggested that marginal costs are around $6.00. Heutte explained that this is an "emerging thing" and a lot of factors play into it, like increased efficiency and productivity, and new drilling, which bring the price down. On the other hand, productions moving "toward the liquid side" help support a market that's lower than the marginal cost. Other factors to consider include the width of the plays and decline rates.

Jourabchi asked if $6.00 is the high range of the marginal cost. Heutte said that, in his opinion, it is.

Hawk said that he has seen prices for unconventional shales range between $2.50 and $7.00 for the marginal costs. At $2.50, he expects that companies are going to keep drilling to maintain their production, like at dry gas well sites. Hawk noted that there is a fair amount of associated gas that's coming with the liquids and the granite wash. Hawk used the Eagle Ford as an example, stating that it has "dry gas, wet gas and it has the liquids; it's one of the big plays that continued."

Friedman commented that that the 2015 mid-case looks fine to him. He isn't a believer in narrow ranges, so seeing a 100 percent change in the price of gas over the course of a year does not seems counterintuitive because there could be an industrial renaissance, more demand and fraction restrictions that cause prices to increase. Friedman pointed out that there could be more demand and less supply. Or, on the low side, one can have continued high oil prices that spur a lot of associated gas developments, for example, that keep prices low. He concluded that he thinks that the forecast should have a wider range.

Hawk noted that spring 2013 was one of the coldest springs in regards to recorded temperatures, so it showed what the market perceives. He stated that at 1.5 TCF (trillion cubic feet of gas), there is a "pretty good surplus… that we've never touched, in storage, in the last seven years. And, that's on top of cushion gas. So it is working gas. I know it takes more time to pull it, but it's there." Hawk states that he doesn't see why the current price should be any different than last year's price, but that the market perceives this differently, stating that "the market sees fewer gas wells, more liquid wells. The market is going to reflect that, it has and it's going to jump like it did." He said that he thinks that Friedman's point is valid and that there should be a "little more consideration on the high end."

White makes a joke about the EIA's competence level and its confidence that gas prices are going to range between $2.50 and $8.50 over the next 20 years. He stated that what the advisory committee has seen over the last several years is a desire to see wider ranges so the Council's scenarios "really work."

In regards to annual average prices, Friedman said that he believes that there's going to be volatility based on weather and storage. He added that the best that the committee can do is hope that they're in-range regarding the forecasts. Friedman shared that five years ago, the consensus among consultants was that long-range gas prices were going to be $6.00 to $9.00. Friedman noted that presently, "the consensus is more like $4.00 to $7.00, and that's just the shale effect."

Hopkins agreed with the others that a wider range makes more sense, and suggested "$3.50 to $7.00 by 2020." He said that he thinks that the $4.00 to $5.50 range is "fairly narrow." Hopkins stated that felt that with production potentially leveling off, "not going the way it has," demand is increasing, so a wider range makes sense.

Jacobsen stated that he agrees with the idea of a wider range, maintaining that it's important to keep in mind that "you're coming up with a Resource Plan, so you want to make sure that you've explored the full range of gas prices." Jacobsen commented that the data doesn't look like the full range is reflected.

Hawk added that it's also important to have the data reflect the prices, as some people may not experience the higher prices.

Jourabchi stated that the Council doesn't limit itself to average ranges in its analytics. The fluctuations that the group sees can increase and decrease, and the graphs that he presented help him get a feel for "how wide the jaws should be."

Van Vactor commented that, regarding hedging, the opportunity cost is always the "spot" price, not what one hedges because if one is lucky enough to buy or hedge gas cheaply, they can resell the gas for a profit. To Van Vactor, the spot price is what matters. He said that he thinks that there is going into an era where there's a much narrower range of gas prices because shale gas is more like a manufacturing cost compared to historical gas and oil development, which had long cycles. He stated that he also foresees shorter cycles and costs that are more observable. He explained that when the costs were more expensive, others expected more LNG imports, which could have raised the costs to $6 to $9. But now, with shale gas going forward, Van Vactor said that he thinks that Jourabchi's costs are reasonable.

Morlan referred to the "gas sausage," when there was deregulation and regulation causing people to seek new gas, which created a surplus that lasted 10 to 15 years. He asked about how the supply of shale gas compared to that "bubble?" and "How long might prices be depressed?" Morlan stated that the answers to these questions can shape the forecast range.

Hawk noted that shale gas has an 18-month storage life, so there needs to be some extra pipeline infrastructure. He believes that producers are hedging more now than 10 years ago.

Morlan then posed a question about volatility graph: Can "shale gas be brought on more quickly? Are those kinds of high prices (for quarterly averages) still reasonable for this analysis?" Morlan said that he thinks that the prices might be too high for volatility, which affects the risk. The meeting participants stated that they saw this volatility in the North East during the winter and discuss the effects of removing a local pipeline. This reflects the difference between very short term excursions and quarterly or longer excursions as used in the RPM.

Heutte stated that, looking forward, there are a lot of "unknowns," such as export. He said that he thinks there are 10 proposed LNG export terminals for northern Vancouver B.C. and that three have national energy board approval, sharing that "they" have a supply from eastern Vancouver B.C. and Alberta. Heutte said that there's a question about how much gas there really is in Vancouver B.C. and a question about its price: "If the B.C. supply starts to have an impact in 2017 or 2018, what will that do the Northwest?" He added that some think that there's a possibility that there could be a "two or three price situation in North America, not just Henry Hub price if the differentials really start to show up and persist. That could go on both directions." Heutte stated that he doesn't think that the advisory committee can assume that current conditions are going to continue going forward, particularly because there are "some big-new demand factors in the horizon that will tend to bring the price up."

Friedman asked if the group supposed to focus on questions regarding the year 2015. Jourabchi said that the Seventh Plan's work starts at 2015 and goes through 2035.

Dickens stated that Tacoma Power supports the use of narrower ranges in forecasts because when they look at gas prices, it's really the shadow price for conservation. He said the cost of gas prices affects the cost of conservation, so a narrower range is a better fit for Tacoma's plans and purposes, from a utility planner's perspective.

Finklea shared, regarding the cost of production, that he saw data that suggested "at a cost-to-production level, we're really looking at the potential of about 900 TCF in the $4.00 to $5.00 range, including Canada." He shared that he thinks the prices aren't going to follow production costs, stating that he disagrees with Heutte's $6.00 figure because he's seen evidence that suggested that a lot of production can occur at the $4.00 to $5.00 range. He added that, in regards to the year 2015, while it seems prudent to have a wider range, people could go out into the market to "lock in low $4 prices for that timeframe."

Hawk noted that one year of Henry Hub prices is about $4.17. Finklea then asked, "Isn't three years about the same?" Friedman shared that the trend does go higher. Jourabchi stated that he obtained the May 2013 information from the Henry Hub price strips. Finklea responded, "With those prices, could you go on the market and do transactions at those values?" Jourabchi confirms that one could.

Preliminary Long-term Natural Gas Price Forecast for Use in the Council's Seventh Plan

Regarding this next topic, Jourabchi stated that he wants to focus more on the long-term because that's where the work of the advisory committee related the most.

Results of NGAC Poll (slide 60)

Jourabchi shared that the respective slide offers a look at the "range of expectations." The graph has three "blocks" of numbers and each block contains a column for minimum, average and maximum price ranges.

Jourabchi explained that he polled the advisory committee about the expectations for the lowest prices, the lowest figure was $2.14 in 2015, and the highest was $4.15. When he compared the lowest figure in the "Range of Low Price Forecast" column ($2.14) to the highest figure in the "Range of High Price Forecast" column ($5.25), he found that the range is roughly 2:1 (about 150 percent). He noted that the lowest price forecast numbers remain around $2.00, while the highest numbers range from $5.25 to $9.46, so the range expands to 4:1 over time. Jourabchi then asked the group if the information seemed reasonable.

Hawk said that he wants to know if he can really purchase gas at $2.03 in the year 2035. Jourabchi explained that this figure is simply part of the range that he collected from the participants.

Council's Forecast of 2012 HH Prices was 2.6 $/MMBTU, Actual HH Price for 2012 was 2.7 $/MMBTU (slide 61)

When Jourabchi showed the respective slide, he explained that while the survey shows a wide range for the Strawman Proposal, he intends to use the average figures from the "blocks" of numbers, as Hawk suggested.

Jourabchi explained that the Council suggested having $4.00 in the low range and said that by 2035, the price forecast will be $4.30 in the low range of the Proposed Henry Hub Forecasts. He stated, "When you compare the low range Henry Hub Forecast to the low range on the poll, the figures differ by $0.60." However, the range of uncertainty is much wider. Jourabchi stated that he expects the mid-range Henry Hub price in 2015 to be about $4.20 and the high range to be $6.40. Jourabchi said that he found it interesting that the forecasted mid-range prices hover around $4.00 for about 20 years. He then asked the group if they feel comfortable with the figures.

Hawk shared that he recently talked to producers at an annual meeting for geologists. The annual advancements in technology, he thought, were "greater than 1 percent." Hawk explained that $5.00 is a "magic number" for producers because when they see $5.00, they are going to drill and hedge their budget "so they can preserve their budget and ability to drill." Hawk stated that he's interested in asking shale producers about the prices that they are willing to accept, the prices that will drive them to schedule a rig. Hawk said that he has friends at Exxon and Shell, and thinks that the committee should ask them about their "drivers" (price motivations).

Dahlberg asked Hawk if he meant a break-even study, or analysis, as producers already conduct those. Hawk replied that he wants to know if producers find $5.00 an attractive price that will prompt them to drill. Heutte commented that he thinks that this is like a "hurdle-rate analysis." Hawk replied that it is, and that "they're" carrying the pipeline at 11 percent.

Morlan then asked that if an analysis found that $5.00 was the magic number, and everyone drilled at this price, wouldn't the overall prices drop? Hawk replied, "Exactly. That's my thinking." He adds that the consequent lowering of prices will benefit the Northwest and put pressure on others.

Jacobsen stated that he thinks the 2020 prices—in regards to renewed development, LNG exports and a possible CO_2 impact—will increase in prices between 2015 and 2020, even more than the poll shows and maybe more than the forecast.

Heutte asked Jourabchi if the graph had a conversion of nominal dollars to constant dollars. Jourabchi said that it did and that it factored in a 1.9 percent inflation rate. Heutte said that he thinks the forecast figures are a bit too low.

Dickens shared that his company uses Wood Mackenzie for a lot of its analyses. He said that the organization's latest spring 2013 forecast has a base case that goes out to about 2030 and is about $1.00 more than the group's forecast because it found that the "trigger" price is around $5.00. Jourabchi asked Dickens what the Wood Mackenzie forecast price is. Dickens stated that it was $6.30 in "2012 dollars." Jourabchi noted that this figure is closer to the group's 2035 number.

Someone stated that at the meeting in Skamania, a person from ICF said that in 2020, the price was going to be $5.50 and $6.00 in 2030. Jourabchi affirmed that those figures are similar to the ones that he was presently sharing. The group had a short discussion about the prices in nominal and constant dollars, finding that the ICF's figures are like the group's mid-range numbers.

Rick Harper offered a note of caution in regards to resources. He stated that there has always been a tradeoff between a less prolific resource and technological change. Historically, technological change has caused prices to drop over time, not rise. Harper said that he has a problem with forecasts that show an ever-rising price in oil or natural gas because it isn't "a good way to look at it."

Hawk then commented that the country is still in an economic depression. He said that he thinks that the market will anticipate another $1.00 if unemployment reaches 5 percent. Jourabchi noted that the Council does look at deviations from the norms, which he will discuss shortly.

White asked, in regards to the slide, if the idea was to reconcile the Council's forecast with the committee's poll. Jourabchi said that this is one of the suggestions that he has "in the package" as the figures from the Straw Man Proposal are similar. He said that there is a difference, however, in the long-term forecast because there is continued growth in the Council's forecasted prices. In the poll, however, there isn't as much growth. Jourabchi stated that "there's a lot more downward pressure on prices." He stated that doesn't think that the downward trend is as realistic because of the increase in demand and LNG, thus the reason why the Council has a faster-growing price range.

White commented, "Our view is closer to the Council's view than the poll." Other group members then agreed that the poll's figures were too low.

Jourabchi stated that if he added a late entry into the poll, "the poll results do go up" because the person has a higher price expectation. White then commented, "It's not about the numbers…It's about the rate of growth and the implications that the rate of growth has on everything we're talking about."

Heutte shared that, regarding the growth rate over the different five-year periods, he doesn't think that the figures would start high and then go down to zero at the end. He stated that convention theory suggests that if rates are high, they'll stay high for a while. Heutte said that, in regards to gas prices, "the market is always wrong, but no one has come up with anything better than that." Heutte said that this is a fundamental issue for him because it's difficult to make a set of projections. He stated that he prefers to see a wide range because of the big changes in the "gas situation" over the last 20 years. Heutte pointed out that shale is one of the larger changes in natural gas and that there are other demand-related factors that he thinks are difficult to predict, so it's hard to determine how all the factors will balance.

Hawk commented that what's happened in regard to turning a source rock into a reservoir rock is really, in terms of natural gas and oil industries, is "quantum-leap technology." Other than "gas hydrated, there aren't a lot out there left in the minds of the beholder." Hawk maintained that while there are technological advancements, none of them are "quantum-leap" technologies, stating, "Natural gas and oil is what fusion will be to the nuclear industry."

Comparison to other forecasts (slide 63)

In the respective slide, Jourabchi explained that he compared the forecasts to those that others have made, like the Annual Energy Outlook 2013 Reference Case, the CEC's 2013 preliminary numbers, the IHS Global Insight forecast, *Natural Gas Week*'s quarterly analyst report, Idaho IRP, NGAC member poll, 2013 to 2014 SNL short-term forecast and other information that he could find.

Various Long-Term Forecasts (2012$/MMBTU) (slide 64)

Jourabchi shared that after combining the different long-term forecasts, the results look a bit messy, and referred to the respective slide. He pointed the out the low, medium and high range forecast slides and noted that the prices are in constant 2012 dollars.

Jourabchi then pointed out the low-, medium- and high-range scenarios of the different forecasting entities. In the graph, the Idaho Power high-range forecasted price is greater than the others. Jourabchi doesn't think that his contacts in Idaho necessarily expect such high forecasted prices.

Jourabchi then reviewed the individual low-, medium and high-range graphs in the next few slides, commenting that there isn't a lot of variation as most are hovering around $4.00 on the low end of the price range. Jourabchi stated that he's thinking of increasing the growth rate in the poll so it isn't flat.

Jacobsen stated that he can't figure out the Annual Energy Outlook's 2014 and 2015 prices because they're a dollar below the prices of the other entities. Jourabchi explained that may be due to the "vintage" of the data.

Hawk said that he thinks that a factor that drives the higher prices past the year 2020 is the retirement of coal plants. He shared that the vintages of the coal plants in the East and Midwest are going to be expired by 2020, so Idaho Power foresaw a bump in consumption, which was reflected in price.

White commented that his company has a similar view as Idaho Power, adding, "If prices are a function of supply and demand, we tend to focus a lot more on supply than demand. And we are very bullish on industrial demand coming back." Consequently, according to White, Idaho Power also shows an increase in prices. Jourabchi stated that White's comment supports the increase in price in the long-term forecasts.

Hawk shared that some speculate the comeback of the steel industry, which is a large gas consumer. He said that in many countries that produce steel—like Italy, China, Japan or Korea—the price of natural gas is two or three times more expensive than in the U.S. Hawk said that he thinss that with the return of the steel industry, there will be an upward pressure on prices.

Dickens told Jourabchi that he just fact-checked the Wood Mackenzie long-term data and found that they projected the 2030 Henry Hub price to be $5.76 in constant dollars.

High Range of Forecast (2012$/MMBTU) (slide67)

After Jourabchi reviewed the slide with the high-range forecast prices of different entities, he stated that he'll review the prices for Idaho Power because Hawk and White believe that the figures may reflect nominal, not constant, dollars, which would account for the high difference in their forecast when compared to the other entities. Jourabchi said that thinks that Idaho Power may use a different inflation rate, which could make the range higher. He then commented that all the forecasts show a rate increase and demand pressure that drive prices higher.

Hawk stated that some forecasters may expect some "roll-overs" in the next 22 years and use what they learned from the recession to make predictions. He pointed out that previous forecasts did not take into account economic downturns "because no one knew how to define the term, but now there's a clearer vision of what this means." Hawk said that he believes that there is no way that 22 years will pass without some type of economic downturn.

Comparison of 6th and proposed Preliminary 7th Power Plan Forecast of Natural Gas Prices (2012$/MMBTU) (slide 68)

While referring to the slide's graph, Jourabchi pointed out that what one see first are the low, medium and high cases for the Sixth Plan. The group joked about the rates for the high case. In regards to the proposed Seventh Plan, at the low case, Jourabchi explained that the price will continue to hang out at around $4.00 through 2035. For the medium case, prices will run a little above $6.00. For the high case, prices will be around $8.00. Jourabchi admitted that the forecast is narrow and should perhaps be a bit wider. He said that he looked at the natural gas prices from 1989 to 2012 and found that the standard deviation is around $2.00, so he thought he'd go above and below the average—about $2.00. Jourabchi stated that it's a coincidence that the number was 2, but it gave him some reliance on the history. He pointed out that he isn't suggesting that history is going to repeat itself. Jourabchi then asked the group if they had any thoughts, comments or suggestions.

Hawk commented that his numbers show 2035 prices at $7.00, $7.70 and $9.00, which reflect the $2.00 deviation. Jourabchi replied that, in regards to creating a wider range, he thinks the range should have a minimum of $4.00, an average of $6.00 and a high end of around $8.00, in constant dollars.

Hawk then asserted that because of the projected demand growth, he thinks that the low range should have a higher price because it has to justify drilling. Other participants in the meeting agree. Heutte commented that he thinks that the low range is fine, but the high range needs to be higher.

White told the group that his company's high end is the same as the Council's, but the low end is higher.

Friedman suggested that the range doesn't have to be symmetrical. He felt that it should "be more skewed to the upside." Jacobsen stated that he agrees because there's a high probability of price escalation between 2015 and 2020 than the graph shows because of coal retirements, LNG, possible CO_2 and greater industrial development across the U.S. He said that he thinks the medium and high ranges should be greater.

Jourabchi shared that he recently learned that post-2025, coal and some of the nuclear plants may be retired, which would put pressure on natural gas demand. Hawk said that this would be the case if the Pacific Northwest markets saw an increase of $0.25 per MMBtu, if 2.4 Bcf per day was exported. He added that while the figures may not seem "right," they're something to consider in the prices.

Fuel Prices Futures in Council's Portfolio Model: "Futures are How the Portfolio Model Stress-Tests Resource Strategies"

Presenter: Dr. Michael Schilmoeller, Northwest Power and Conservation Council

Jourabchi introduced Dr. Michael Schilmoeller, who assists with the committee's data and analysis by introducing uncertainty.

Dr. Schilmoeller began his presentation by stating that the main message that he wants to communicate is that the futures for natural gas prices that the Council uses in the Portfolio Model serve as a way to stress-test the resource strategies. He explained that it's the Council's approach that they can't forecast the future. Dr. Schilmoeller stated that in the first load forecast and natural gas forecast graphs presented earlier in the meeting, there were no medium cases, just high and low cases to help "break the region of the habit of zeroing in on the point forecast of the future." He said that this was consistent with what the Council has done in the past.

Dr. Schilmoeller then referred to the “long-term management fiasco” of the 1990s, when there was a company that became too big to fail. He explained that there were about $3 trillion under the control of the hedge fund. The retirement accounts for Harvard University and the U.S. Senate had large investments in the company with long-term capital management. He explained that after the ordeal, everyone got their money back, and one of the innovations that came out of the incident from the banking industry was the concept of “stress testing” portfolios.

Dr. Schilmoeller told the group that stress testing involves exposing a model to futures that are extreme to see the implications on the value of the portfolio and determine if the results are agreeable. He gave the following example, “What would happen if the cost of oil doubled or was cut in half?” Dr. Schilmoeller stated that while the questions aren’t forecasts, they help find the vulnerability of a given portfolio. Dr. Schilmoeller shared that the Council asks such questions when developing a resource strategy. He explained that Council develops strategies that are “fairly robust” as it’s “not really trying to optimize,” even if the assumptions turn out to be wrong. For example, the Council may examine the risk of needing resources when there’s no foresight to construct them and looks at the downside of building resources and discovering that they’re not needed, as both have an implied cost.

Sources of Uncertainty (slide 71)

Dr. Schilmoeller told the advisory committee that the Council considers a host of different sources of uncertainty. Referring to the respective slide, Dr. Schilmoeller stated that natural gas prices were a source of uncertainty for the Fifth Power Plan. In the Sixth Power Plan, construction costs, technology availability, conservation costs and performance were sources of uncertainty.

Different Kind of Risk Modeling (slide 72)

The way that the Council does its modeling to come up with a portfolio of resources differs from other utility companies, according to Dr. Schilmoeller. The Council assumes that it can’t foresee the future and it doesn’t rely on a single forecast. He said that when the Council simulates the building out of resources, it uses a “decision criteria.” The model internally does an assessment and a forecast of commodity and fuel prices. Dr. Schilmoeller explained that, based on what the model thinks the future will look like, it’s going to make a decision about new construction. The model also considers regional energy adequacy and future models may consider capacity. He explained that if the region has sufficient resources, the model would build the “least-cost resource irrespective of assumptions” about a plant covering its own costs.

Dr. Schilmoeller noted that the plans adapt to the futures that the models create. He provided the example that if there’s a future that shows no present need for resources and the need for future resources is unlikely, the model will elect to not proceed with construction or “mothball” a plant.” Dr. Schilmoeller said the model also adapts to other policies, like conservation.

In regards to the term “options” in the slide’s second point, Dr. Schilmoeller explained that it does not refer to financial options or to the region optioning power plants. Instead, Dr. Schilmoeller pointed out, “options” are like what planners or real-time operators do on the trading desks and operating floors, where they make decisions about the types of power plants they want standing-by. He explained that they don't know what's going to happen, but they do know that there's a need operational plants "in case something happens." Dr. Schilmoeller stated that the model makes recommendations about what the Council should "site, license or get ready to pull the trigger on" so new construction can begin as quickly as possible if a future indicates that such actions are prudent. Therefore, *options* are like contingency plans.

In regards to the third point on the slide, "Scenario Analysis on Steroids," Dr. Schilmoeller explained that the Council exposes each resource strategy to 750 different futures. The futures differ in extreme ways, similarly to the utility industry's scenario analysis. He gave the example of a future where gas prices are low, stay low for 20 years and continue to grow, but a couple of event cause a short-term disruption and market disequilibrium cause prices to "take an excursion."

Observations (slide 73)

Dr. Schilmoeller shared that stress testing includes considering extreme and likely futures, not predictions, to test how a resource portfolio may respond to and look at unusual relationships. He said that the "mortgage crisis" is an example of where industry leaders forgot to do stress testing and forgot that the traditional correlation between assets and collateralized debt obligations could move in the same direction at the same time because they are not really independent. Correlation structures change when the rules change. Reading from the slide, Dr. Schilmoeller asserted that stress testing is "thinking in terms of effect and categories of uncertainty, rather than detailed causes."

Dr. Schilmoeller explained that in the Sixth Power Plan, there were futures where carbon taxes were $0 and futures where carbon taxes went up to $100 per ton. He shared that the tests revealed that the region is vulnerable to the loss of its coal plants. Even a low tax could cause the plants to operate at a reduced capacity; the cost of running the plants would increase and market costs would increase. Dr. Schilmoeller stated that the Council obtained such results before the closing of the plants in Boardman and Centralia.

Dr. Schilmoeller pointed out that the model shows meeting 85 percent of the load growth with conservation and the net of RPS resource requirements declining over time. He explained that the model also suggests that it may be advantageous to site and license as much as 3500 megawatts of combined cycle combustion turbines in the years 2018 to 2019 because, if the coal plants aren't there, there's a big hole to fill. Therefore, concluded Dr. Schilmoeller, it's better to be prepared.

Dickens asked Dr. Schilmoeller if the extreme futures take into consideration regulatory uncertainties. Dr. Schilmoeller said that they do as new technologies reduce commodity costs. He explained that, historically, commodity costs can increase because of regulation and legislation. For example, new gas technologies may prompt new regulations and bring up water quality issues, so inadvertent methane leak concerns could increase the cost of gas. Therefore, yes, regulatory uncertainties are important factors that get considered.

Hawk then commented that "fugitive" gas doesn't necessarily raise the price of gas because it's a cost that the producers absorb, the market won't reflect this type of incidence. Dr. Schilmoeller then asked Hawk about producers recovering the cost of cleanup if regulations were in place. Hawk responded that the producers can't pass on the cost or the market wouldn't allow if it resulted in drilling fewer wells. After Dr. Schilmoeller thanked Hawk for his comment, Hawk spoke about his past experiences with another company. He said that since the company had competition, it had to absorb such costs.

Friedman asked Dr. Schilmoeller, "Is this a difference that makes a difference?" He wondered if the price of gas would increase if fewer wells were drilled. Dr. Schilmoeller said that the prices would have a short-term increase. Hawk added that if a well is drilled and completed for $8 million, then the other $100,000 is a cost that the company would have to absorb in respect to fugitive methane emissions. Dr. Schilmoeller stated that this is true if one knows that this is the value.

Riding stated that a company isn't going to drill it if prices haven't recovered enough. He added that, if the costs of future production increase, it will be reflected down the road.

Hawk shared that "they" love to use the term "fugitive methane emissions," but the truth is that that the term is a "red herring." It's scientifically bogus.

Dr. Schilmoeller told the group that it's important to remember that constructed resources have 25- to 35-year lifetimes, and there's a concern about "consequences" that could happen during this time. He explained that the ability to forecast over this time scale is limited and long-term costs would be significant to the rate-payer.

Hawk referred to his previous comment and stated, "Regarding fugitive methane emissions, you're safer smoking 100 feet from a drilling rig than you are 15 feet away from a cow." The group laughed.

Range of Forecast Natural Gas Price Delivered to Electric Utilities PNW East & Deciles Used in RPM (2006$/mmBTU) (slide 76)

Dr. Schilmoeller explained to the group that when they first see the futures plotted on a graph, referring to the respective slide, it looks busy. He said that the graph shows the likelihood of events that may occur in a quarter, a price within the deciles.

Dr. Schilmoeller stated that the graph covers 20 years, 80 annual quarters. There's a 10 percent chance of seeing a price between $10 and $12 per million BTU (in 2006 dollars) in the respective quarter. Dr. Schilmoeller said that the data doesn't say much about the future, "but if there's a single quarter in any of the 250 futures, over which (the Council) saw this type of price, it would contribute to that decile." He noted that the graph isn't an equilibrium price forecast; they're single quarter excursions.

Dr. Schilmoeller stated that after the Fifth Power Plan, there was a quarter that reflected $10 to $12 per million BTU. He shared that the Council wondered if it should redo the plan, but he advised them not to redo the plan because they knew the effect that such an occurrence would have on a plan. Dr. Schilmoeller stated that the plan is "robust with respect to these kinds of changes."

Dr. Schilmoeller stated that the Council just started the Seventh Power Plan and the data reflected in the last few slides are from the Fifth and Sixth Power Plans. He shared that the intent is to bring the data used in the Seventh Power Plan to the advisory committee and discuss the narratives that support the futures. If any of the futures seem feasible, they're fair game.

Dr. Schilmoeller shared that the Council performed "thresholding" on the futures. He said that in the Fifth Power Plan, they started with a carbon tax that went up to $40 per ton of CO_2. He stated that the Council discovered that it could "back the data down" in regards to magnitude and probability before it affected the plan, which helped more people feel more comfortable.

Dr. Schilmoeller explained that when thresholding, it's important to learn how much data has to change before the "answer" has to change. He stated that the Council learned that lead times for coal plants, not carbon, in the Fifth Power Plan drove the most concern because so much could happen in three and a half years. This demonstrated that lead times were a riskier type of resource than combustion turbines, which only take a year and half to construct. Wind power plants only take about six months to construct. Dr. Schilmoeller added that the Council does try to reconcile with its official forecasts, and it will provide this comparison in the future.

At this time, Jourabchi noted that Dr. Schilmoeller's topic deserved more time because it helps the advisory committee know what happens with the forecasts after their creation.

Hawk asked if the forecasts included interstate transportation. Jourabchi said that they do and that the Council looks at the pipelines that will most likely get used, the transportation rates for the pipelines and the burner-tip price of electricity that utilities pay. The Council then relates the data to Henry Hub prices; the considerations are comprehensive.

Hawk then asked what would happen with the Northwest pipeline over the next 22 years in regards to price increases. Dahlgren responded, stating that a lot of it depends on expansions, contracted capacity and regulations, particularly safety regulations. Hawk asked if the changes have the potential to add $0.05 to the cost. Dahlgren stated that her organization looked in to this topic, as if O&M and G&A went away and they were left with nothing, and found that the rate would change by $0.01 so.

Next Steps (slide77)

Presenter: Massoud Jourabchi, Northwest Power and Conservation Council

Jourabchi moved on to the next part of the meeting, stating that he would review the comments made and use them for the proposed preliminary prices for natural gas. He shared that his office will make a Council presentation in Seattle, WA in July 2013 to seek approval for the proposal. If the Council in Seattle approves the proposal, it will affect the future electricity price forecast and the retail rate forecast. Jourabchi said that he expected an updated forecast by November 2013 for electricity, which includes an updated demand forecast. In 2014, the Council will have some preliminary numbers from its Resource Portfolio.

Jourabchi then asked for feedback about the presentation's format and about having the meeting after the Northwest Natural Gas Association Conference.

Hawk shared that some of the people from ICNU couldn't attend because they were at another meeting, but he thought the format and timing was "really good." The group agreed that the meeting's format worked out well. The next Northwest Gas Association conference is on June 4 and 5, 2014.

Proposed Forecast of Refiners Acquisition Cost (2012$/barrel) for Use in Council's Seventh Power Plan (slide 80)

Jourabchi reviewed the proposed refiners acquisition cost forecast for the Seventh Power Plan on the respective slide. He noted that in the Low Case, the prices go down, keeping in line with feedback from the advisory group.

Heutte asked Jourabchi about adjusting to nominal dollars. Jourabchi said that when doing this, the figures increase 1.5 times, so the High Case is around $200.

Comparison of RAQ Cost 2012$/Barrel (slide 82)

Jourabchi showed the respective slide and Hawk stated that he's surprised that the low figures continue to decline. He asked if they increase at some point. Jourabchi replied that the downward trend occurs in many forecasts.

Hawk stated that "Arab nations" still have plenty of oil and gas resources, particularly in the smaller undeveloped fields, and they have "tremendous" shale resources. Hawk shared that studies that he has seen show the U.S. being 70 percent self-sufficient by 2020 or 2030, and obtaining oil from Mexico and Canada.

Jourabchi referred back to slide to show that others, like IHS Global Insights, have declining prices in the Low Case and slight improvements in the Medium Case, but a long-term decline.

Hawk stated that while people are going to find more oil, demand is on the rise as more individuals want to own cars. Van Vactor added that $6.00 gas results in oil costing $36 per barrel in Btu value. Some group members began to talk about oil prices and Jourabchi suggested continuing this conversation via email. He also shared that all the slides from the meeting will be available online after the meeting.

Finklea stated that he wants to know if the committee will receive a draft of the proposal that the Council in Seattle will receive. Jourabchi said that he can make this happen and that he'll send out the updated data for the proposal in the next week, encouraging everyone to send him commented and questions.

Jourabchi then told Heutte that the cost in nominal dollars is $2.09 and $1.40 in constant dollars.

Comparison of PRB Coal Price Forecasts 2012$/MMBTU (slide 84)

Jourabchi referred to the respective slide, commenting that the graph shows the current proposal for coal. He stated that he isn't sure why the Annual Energy Outlook has high expectations for PRB coal prices. Jourabchi then pointed out that the yellow line shows the SNL forecast.

Hawk commented that he wonders if the entities assumed that the higher-sulfur eastern coals are going to have to "go by the wayside" and that the PRB price is going to increase because it will be the "premier fuel." Jourabchi validated the hypothesis and shared that there are issues with low production.

Historical and Proposed Forecast of PRB Coal Prices (2012$/MMBTU) for Use in Council's Seventh Power Plan (slide 85)

Jourabchi stated that the graph on the respective slide offers a historic look at coal prices and reflects the range of the forecast in the Council's proposal.

Comparison of 6th and proposed 7th Power Plan Forecast of Refiners Acquisition Cost (2012$/Barrel) (slide 86)

Jourabchi explained that the respective slide shows a price forecast comparison of the Sixth and Seventh Plans. He pointed out that in the Seventh Plan, the Council lowered expectations, except in the High Case, where the trajectory remained the same.

Proposed PRB price Forecast 2012$/MMBTU (slide 87)

Jourabchi shared that the respective slide shows the range of proposed prices for PRB coal.

Hawk asked about the Nevada legislature to learn if it drafted a bill to shut down the Henderson Coal Fire Plant. Jourabchi replied that the bill was drafted, but he's not sure if it was signed, adding that retirements of plants like these are considerations for the Wholesale Price Model Analysis.

Jourabchi thanked the members of the advisory committee again for their participation and concluded the meeting at 12:35 p.m.

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