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VIA ELECTRONIC MAIL

Public Utility Commission of Oregon
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Attn: Filing Center

Re: **LC 45, NW Natural 2008 IRP**

Below are NW Natural's responses to the questions issued by Northwest Pipeline GP on July 3, 2008. The Company's response to Question No. 3 contains confidential and proprietary information, and is provided separately subject to Protective Order 08-337

Question 1:

A recent article in *The Oregonian* stated that the cost of the entire proposed Palomar line from Madras to Astoria, Oregon would be about $650 million and that about half of the line would go from Madras to Molalla. Extrapolating from the article, Northwest estimates the rate for 200,000 Dth/d of capacity, the volume NW Natural assumes will be subscribed on Palomar East could range between roughly $0.62 and $0.69 per dekatherm (an $0.11 to $0.18 rate premium over Northwest's $0.41 rate). How does NW Natural reconcile the resulting rate increase with the estimated $0.02 rate increase given to Staff in the UI 276 process?

Response:

The $650 million project cost estimate assumes construction using 36" pipe with 1,000,000 Dth/d of capacity in the Madras-Molalla east zone. We understand that the pipeline would be only built using 36" pipe if shipper commitments are sufficient to support this capacity size. With 1,000,000 Dth/d in billing determinants, NW Natural estimates that its shipper rate most likely would be around $0.20, or less than half Northwest Pipeline's rate. This would result in a rate decrease for customers.

In the hypothetic example postulated by the question wherein there is only 200,000 Dth/d of contracted capacity, then the pipeline would most likely be constructed using either 24" or 30" pipe. This would substantially lower the cost estimate for the east zone to be less than 50% of $650 million. Hence, the rate calculation made in the question is erroneous – it has inconsistent capacity assumptions between capital cost and billing determinants.

Finally, it should be noted that NW Natural's precedent agreement for the Eastern Zone is a negotiated rate with a rate cap formula. Should the FERC authorized cost-based recourse rate turn out to be more than a specified rate cap (as calculated by the formula, see confidential Response 3), then NW Natural as a Palomar shipper would not pay the higher recourse rate. Given this, NW Natural's LDC customers are not exposed to a potential rate increase (beyond the negotiated rate cap).

Question 2:

Northwest has relatively recent experience in constructing capacity in the Pacific Northwest, including its Evergreen Project (FERC Docket No. CP02-4) in 2003 and its Capacity Replacement Project (FERC Docket CP05-32) in 2006. Additionally, Northwest has prepared cost estimates for the proposed Pacific Connector Gas Pipeline (an approximate 230-mile pipeline to connect the proposed Jordan Cove LNG facility in Coos Bay, Oregon to Northwest's Grants Pass lateral system in Douglas County, Oregon and to PG&E's and Tuscarora's systems near Malin, Oregon) and the Blue Bridge Pipeline Project (up to 172 miles of pipeline looking along the Columbia River Gorge and the 1-5 corridor to provide up to 500 MDth/d of capacity to serve the market growth in the region). Both Pacific Connector and Blue Bridge have been proposed for service in the same timeframe as Palomar. Northwest is also familiar with the Palomar route and some of the construction challenges to be faced in building Palomar East. Palomar East's sponsors will face many geographic and environmental hurdles, such as multiple river crossings, extreme elevation changes and construction through old growth forest habitat for high profile threatened and endangered species, such as the spotted owl. Additionally steel and construction prices have increased dramatically. Based on these factors, Northwest estimates the costs for Palomar could be considerably higher than referenced in *The Oregonian.* Have the geographical and environmental challenges and increased material and construction costs been included in the Palomar East cost estimate?

Response:

The Operator for Palomar is GTN, a TransCanada subsidiary. As such they are responsible for the project cost estimates, including engineering and environmental analysis. GTN and TransCanada have extensive experience in the pipeline business. While NW Natural is a part-owner and has performed a third-party cross-check on the cost estimates, it is primarily relying upon the quality of GTN's work.

We will also note that Northwest Pipeline and GTN are partners in the proposed Sunstone pipeline project. As part of this process, we assume that the two companies have exchanged pipeline construction cost information and are relatively aligned around cost estimation methodologies.

The geographic and environmental challenges associated with the Palomar route have been factored into the cost estimate. However, the $650 million cost estimate is about a year old. Given the increase in steel prices over the last year, it would not surprise us if an updated project cost estimate came in somewhat higher. Again, NW Natural's LDC customers are not exposed to this upward cost pressure due to NW Natural's negotiated rate for shipping gas on Palomar which includes a rate cap.

Question 3 is provided separately, subject to Protective Order No. 08-337.

Question 4:

If NW Natural's rate is fixed regardless of the cost of construction, has the possibility that other Palomar East shippers may have to subsidize NW Natural's rate in order for the Palomar sponsors to earn a reasonable return been taken into consideration? What is the likelihood that Palomar East would be fully subscribed if other shippers had to subsidize NW Natural's rate, and would the need for such subsidization impact the viability of the project?

Response:

It is our understanding that according to FERC non-discrimination rules, Palomar must be willing to offer similar rate terms to similarly situated shippers. To qualify as similarly situated, another shipper would need to subscribe for a substantial amount of capacity, as has NW Natural. These shippers would have the choice of: a) taking the FERC recourse rate, b) negotiating their own rate, or c) qualifying for a negotiated rate similar to NW Natural's. Given the choices they have, it is highly unlikely that other shippers with any substantial contract volumes would be subsidizing the project.

It is possible that small volume shippers may have a higher rate than NW Natural's.

Question 5:

Does the selection of the Palomar 100 case as the Preferred Portfolio take into consideration the risk of rate increase on Northwest due to NW Natural's turn back to Northwest of 77,000 Dth/d in the Palomar 100 case? NW Natural's assumptions do not seem to take this risk of cost reallocation into consideration. Not only could this cost increase be applied to NW Natural's remaining 275,044 of firm Northwest capacity, but it could also be imposed on other Northwest customers generally including other utilities regulated by the OPUC, such as Portland General Electric, Cascade Natural Gas Corporation, and Avista Corporation as well as industrial customers in the state of Oregon.

Response:

The economic analysis did not consider any potential second order impacts to Northwest Pipeline's rates. This capacity is likely to be re-contracted and it is not clear that rates would be impacted.

The newly proposed 500,000 Dth/d Blue Bridge pipeline project, jointly sponsored by Northwest Pipeline and Puget Sound Energy, indicates that there is a perceived need for additional pipeline capacity going through the Columbia Gorge above and beyond what currently exists. This suggests that the market demand and value of the existing 77,000 Dth/d that NW Natural would turn back to Northwest Pipeline is quite high.

Question 6:

NW Natural justifies Palomar East by citing the need for "supply path diversity" and the need to minimize risk associated with its dependency on one pipeline. Does the selection of Palomar 100 case as the Preferred Portfolio take into account the risk reduction associated with Northwest's proposed Blue Bridge Pipeline project which would loop Northwest's system along the Columbia River Gorge?

Response:

The Blue Bridge project was announced after the completion of NW Natural's IRP analysis, so it was not explicitly modeled. However, it should be noted that the sponsors of Blue Bridge touts that much of its pipe will be located in the same right-of-way as the existing pipeline through the Columbia River Gorge. Early estimates are that 60% of its 156 miles of pipe through the Gorge will be in the current pipeline right-of-way. Moreover, we understand that Blue Bridge relies on existing NWP pipe between Stanfield and Plymouth. Accordingly, it does not offer the same risk reduction that Palomar provides.

Also, regarding cost, Blue Bridge involves a total of 172 miles and compression added at three stations (Plymouth, Washougal and Chehalis). By comparison, Palomar is only 108 miles long and involves no compression, although it does require incremental transportation on the GTN system from Stanfield to the vicinity of Madras. Thus it would appear that Palomar should be a less expensive project than Blue Bridge. A more thorough comparison will be possible when Blue Bridge's potential rates are revealed.

Question 7:

Why are the "Total Supply Costs" higher in the No Palomar, No CD Turnback case beginning in 2009-10 than in the Palomar 100 case?

Response:

The *SENDOUT*® model simultaneously re-optimizes all components of the portfolio and generates a unique least cost dispatch solution for each individual scenario based on the resource options available. Among the interrelated decisions are approximately 1,900 time dependent resource mix (capacity and DSM sizing) decisions. Consequently, changes to one resource decision may potentially impact all other resource decisions.

The total supply costs are higher in the "No Palomar, No Turnback" case compared to the "Palomar @ 100" scenario, because fewer cost effective incremental resource options are available in the "No Palomar, No Turn-back" scenario. Palomar provides 100 MDT / day of capacity, while the associated NWPL CD turn-back is limited to 77 MDT / day. Thus, Palomar provides net incremental capacity of 23 MDT / day. Due to incremental net capacity provided by Palomar, additional capacity is also selected upstream of Stanfield, providing access to incremental AECO supply. Over the study period, the optimal mix of resources selected in the "Palomar @ 100" scenario provides more access to less expensive supply; provides increased flexibility for deliveries to downstream markets; and decreases the need for more expensive local resource alternatives. The combination of these factors allows supply to be sourced and dispatched more effectively, and thus, costs differ between the two scenarios.

However, the "No Palomar, No Turnback" scenario does not reveal higher costs until 2010 / 2011. In fact, the "Palomar @ 100" scenario is slightly more expensive in the 2009 /2010 gas year. Due to the lower level of incremental capacity selected in 2010 /2011 in the "Palomar @ 100" scenario, compared to that selected in the "No Palomar, No Turnback" scenario, more storage working gas is required for the 2010 / 2011 winter season. Thus, the model dispatches more supply during the 2010 injection season to meet the additional storage inventory requirement. Compared to the "No Palomar, No Turnback" scenario, the "Palomar @ 100" scenario dispatches an additional 1.743 MDT supply in the summer of 2010 in order to source additional storage injections of 1.635 MDT. As a result, supply costs are slightly higher for "Palomar @ 100" during the 2009 / 2010 gas year, though the costs over the entire run horizon are less in the "Palomar @ 100" scenario, compared to the "No Palomar, No Turnback" scenario.

Question 8:

Why does the need for satellite LNG at Eugene and Salem differ between the two cases, and why is the increment of "WFM Main" higher in the in the No Palomar, No CD Turnback case when the capacity provided by Palomar is only replacement capacity from Stanfield across the Columbia River Gorge?

Response:

Access to incremental capacity at the city-gate, such as Palomar, impacts downstream resource sizing decisions, including Satellite LNG. Due to less access to incremental capacity in the production areas (see response to Question 7 above), upstream capacity associated with Palomar, the "No Palomar, No Turnback" scenario requires more localized capacity such as Satellite LNG. Less Palomar capacity at the Portland city-gate exacerbates limitations associated with capacity displacement to serve demand down the Grants Pass lateral.

The model initially selects additional "WVF Main" capacity (6 MDT/d) in the "No Palomar, No Turn-back" scenario, compared to the "Palomar @ 100" scenario (4 MDT/d) and also selects more Satellite LNG. The net increase in interstate pipeline capacity provided by the "Palomar @ 100" scenario allows the model to postpone the selection of additional WVF capacity until later in the planning horizon. The "Palomar @ 100" scenario selects incremental WVF capacity beginning in 2021 / 2022 and ultimately reaches 3 MDT/d in 2028. This capacity is identified in the table on page 5-3A-22 in Appendix 5 as "WVF Phase II."

Question 9:

NW Natural state pages 3-11 to 3-12 that this IRP assumes recall of 7,000 Dth/d of capacity currently in evergreen with a one-year notice period. This is reflected in both cases. Why is the recall of all or part of the 30,000 Dth/d release that terminates in 2010 not considered as part of the No Palomar, No CD Turnback case? Would that be a cheaper alternative than acquiring incremental Northwest capacity in the last three years of the plan?

Response:

Either party to the 7,000 Dth/day capacity recall arrangement had the right to terminate that agreement for any reason. NW Natural exercised that right because the analysis indicated benefits by doing so. The 30,000 Dth/day agreement contains a right by the other party to continue that arrangement past 2010. Informal discussions with the other party indicate that they indeed are interested in continuing the agreement post-2010. Hence, termination of that agreement is not being modeled at this time.

Question 10:

NW Natural currently transports GTN from Kingsgate to Stanfield to deliver to its Northwest capacity that originates at Stanfield. Under its Palomar 100 case, NW Natural will have to transport the gas further on GTN between Stanfeild and Madras. Since GTN has mileage-based rates and fuel. Based on GTN's currently effective rates and fuel, Northwest estimates that NW Natural would have to pay an additional approximately $0.09 per dekatherm (assuming $7 gas). Has NW Natural included an assumption for this cost? Has NW Natural factored in to its analysis potential rate increases on GTN if the Ruby Pipeline that is proposed to deliver Rockies gas to Malin, Oregon is constructed?

Response:

As mentioned in the response to Question 3, the ceiling rate on Palomar explicitly considers the incremental cost of transporting on GTN from Stanfield to Palomar.

The impact of the Ruby Pipeline has not been modeled. De-contracting on GTN and resulting rate increases are certainly one possibility. However, a half-dozen (or more) pipeline expansions are currently proposed to evacuate gas from the Rocky Mountain supply basin to various markets, and any of them could increase the cost of Rockies supplies delivered in the Pacific Northwest versus Canadian supplies, which would in turn increase the utilization of GTN. Palomar is well-positioned to receive gas via GTN from the North or the South, whichever new pipeline is constructed (or if neither pipeline is constructed).

While much is speculation at this moment, what is clear is that efforts to increase utilization of GTN would benefit NW Natural's customers if they can minimize or eliminate the rate increases suggested in the question. Palomar fits well with that strategy.

Question 11:

NW Natural has been a major proponent of the proposed LNG projects on the Columbia River, like Bradwood Landing. Did NW Natural also consider subscribing to capacity on the proposed Sunstone Pipeline that is being jointly developed by Williams Gas Pipeline, TransCanada Pipeline and Sempra Pipelines & Storage to bring additional Rockies supplies to Stanfield?

Response:

While not specifically targeted at the Sunstone Pipeline but in recognition of various proposed interstate pipeline projects that could access additional Rockies supplies, NW Natural did consider incremental capacity additions that could bring additional Rockies supplies to Stanfield. This is discussed in Section V. A., Interstate Capacity Additions, in Chapter 3 of the IRP, specifically where it refers to new capacity upstream of NWPL mainline capacity providing access to the Rockies and Alberta supply areas (page 3-20). Table 3-5 lists the availability of generic Rockies – Stanfield contract demand of 1,062,000 Dth/d.

In addition, NW Natural executed a deal in February 2008 with an existing shipper on the Northwest Pipeline system that will bring 12,000 Dth/day of vintage-priced capacity from the Rockies to NW Natural in the 2012-2017 time frame (the exact date is to be selected by the other party by mid-2009). This satisfied NW Natural's need for incremental mainline capacity, i.e., the option of incrementally priced expansion capacity on Northwest Pipeline was not selected in the IRP analysis. Accordingly, NW Natural did not participate in the Sunstone open season.

Please call if you have questions.

Sincerely,

/s/ Inara K. Scott

Inara K. Scott
Manager, Rates & Regulatory Affairs

CERTIFICATE OF SERVICE

I certify that I have this day served the foregoing REPLY COMMENTS IN DOCKET LC 45 upon all parties of record in this proceeding (LC 45), by e-mailing an electronic copy to the following parties or attorneys of parties:

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DATED at Portland, Oregon, this 17TH day of July 2008.

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