the Colstrip generating units; 2) the amount of energy Puget should assume it will receive under the March Point power purchase agreements; 3) the gas price used by Puget's AURORA model (a fundamentals power cost model); and 4) a reasonable level of expense for call options used to reserve peaking power. The first three of these adjustments result in a reduction of the costs Puget has requested in this proceeding of approximately $29.5 million. This result was produced running the AURORA model through all 40 water years. The bulk of this amount is related to an adjustment to the gas price used by the Company. The fourth issue, related to the call options reduces the *revenue requirement* requested by Puget by about $9.8 million.

The remaining, but substantial, $40.3 million difference between ICNU's adjusted base power cost and Puget's proposal relates to the Tenaska power purchase agreement and the associated regulatory asset. In this proceeding, Puget is seeking a cost increase for the power procured from Tenaska that is far in excess of the contractual rate under the original contract. The Commission deemed this rate to be imprudent in docket numbers UE-920433, UE-920499 and UE-921262. Subsequently, in docket number UE-971619, the Commission approved the creation of a regulatory asset associated with the Tenaska agreement based upon Puget's restructuring or amending the contract. At the time Puget restructured the contract, the Company projected that the agreement would produce a substantial ratepayer benefit. In actuality, however, ratepayers have incurred substantial additional costs under the restructured Tenaska contract and these costs exceed the likely remaining benefit. Accordingly, ICNU recommends that the regulatory asset be written off and removed from rate base.

[redacted] It is this type of fundamentals analysis that is needed to determine a base gas price for this proceeding.

Q. HOW DO THE FORWARD GAS PRICES CONTAINED IN THE FUNDAMENTALS REPORT FOR THE RMC COMPARE TO PUGET'S PROPOSAL IN THIS DOCKET?

A. [redacted]

tool and the associated inputs. In other words, from my prospective, the model that Puget used for its fundamentals analysis for risk management purposes is a black box. On the other hand, I have been aware of the CEC tool for many years, having analyzed the original FORTRAN source code. Should the Commission determine that the Puget gas price forecast from the December 2003 RMC meeting is more appropriate than ICNU's, this would increase ICNU's recommended revenue requirement by $2.6 million (AURORA comparison of average water year).

Q. PLEASE SUMMARIZE ICNU'S PROPOSED ADJUSTMENTS RELATED TO THE AURORA POWER COST MODEL.

ICNU has proposed adjustments related to the manner in which the Company has improperly modeled the following elements in its power costs in this case: 1) Puget has unnecessarily increased the outage time of Colstrip Unit 3; 2) Puget overstated the generation at the March Point facility; and 3) Puget has used a flawed gas price forecast in the Company's AURORA model. If the Commission were to adopt ICNU's recommendation on all of these issues, it would result in a overall reduction to *revenue requirement* of approximately $29.5 million, the bulk of which is related to Puget's flawed gas price forecast.

D. <u>CALL OPTIONS</u>

Q. PLEASE EXPLAIN THE CALL OPTION EXPENSE PUGET IS PROPOSING TO INCLUDE IN ITS BASE RATE DETERMINATION.

A. Puget has included approximately $10.5 million in its PCORC filing associated with certain winter peaking options designed to address the risk of extreme temperature variations from November 2004, to February 2005. ICNU recommends that the Commission disallow *$9.3 million* of this expense because it is excessive and these options are not a cost effective manner of addressing weather risk.

Exhibit No. ___ (WAG-16) contains a listing by FERC account and resource (or contract) of the power costs Puget is proposing to recover in the three columns under the PCORC acronym. Towards the bottom of this exhibit, there is an account 555 row simply entitled "Capacity," for which Puget has included $10,490,000 in its PCORC filing. This $10,490,000 represents the level of option costs (really an upfront reservation charge) that Puget is proposing to include in its base rate determination. This is an excessive amount for these peaking options given the actual risk of extreme weather events that Puget faces.

Q. HOW HAS PUGET CALCULATED THE PRICE OF THESE PEAKING OPTIONS?

A. Exhibit No. ___ (DWS-9C) replicates the assumptions and calculations employed by Puget to arrive at the $10.5 million value. Lines 1 and 2 of this exhibit show the only costs incurred to date for the rate year from the purchase of a single 50 MW option at a reservation price of [redacted] Line 3 indicates that Puget expects to have a remaining unfilled capacity of 2,729 MW-months based upon the extreme temperatures shown in line 4. These temperatures are far colder than the 23 F expected peak hour temperature value. Lines 8 through 10 show the costs assumed by Puget for obtaining call options for the remaining unfilled extreme peak need based upon the assumed prices shown in lines 6 and 7. [redacted]

Q. HAS PUGET PERFORMED AN ANALYSIS ON THE COST EFFECTIVENESS OF DAILY CALL OPTIONS THAT PRODUCED SIMILAR RESULTS?

A. Yes. Exhibit No. ___ (DWS-11C) contains a presentation to the RMC on May 1, 2003, regarding the need to acquire additional call options for the 2003 winter. [redacted]

The minutes from that meeting contain the following recommendation:

> [redacted]

Exhibit No. ___ (DWS-12C) at DWS/2.

Q. DOES IT APPEAR THAT THE COMPANY HAS FOLLOWED THROUGH WITH THIS RECOMMENDATION?

A. Yes. Since the recommendation was made to the RMC, Puget has only procured 50 MW of daily options and focused more on exchange power arrangements to achieve winter reliability needs. The last rate case stipulation adopted $11.2 million of reservation costs for option purchases in 2002. However, the Company only expended [redacted] for the winter of 2003/2004 and all of this cost was incurred prior to the RMC meeting. For the winter of 2002/2003, the Company only expended [redacted]. Finally, Exhibit No. ___ (DWS-13HC) contains a [redacted]

1998 through 2003. This obviously is a substantial difference from Puget's projected [redacted] benefit for this period. For the remaining term of the contract (2004 through 2011), the update shows the limited net present value to the Company's ratepayers does not offset the real costs that have been borne by ratepayers to date. In fact, the overall NPV is actually a ratepayer cost of [redacted].

Q. HOW HAS THE SUBSTANTIAL BENEFIT PROJECTED BY PUGET AT THE TIME IT REFORMED THE CONTRACT RESULTED IN A COST TO CUSTOMERS?

A. The original analysis done by Puget relied upon long-term gas price quotes from a number of providers as shown in the last several rows of Exhibit No. ___ (DWS-14C) at DWS/1. However, since the buy out, Puget has primarily relied upon spot market purchases for the procurement of gas. See Exhibit No. ___ (DWS-15). Accordingly, as the actual prices have surpassed the price quotes, the projected ratepayer benefit from reforming the contract has turned into substantial ratepayer cost. Simply put, Puget failed to enter into any kind of hedging arrangement to lock-in the benefit that could have occurred in reforming the contract. If Puget had been able to achieve the gas prices that the Company assumed at the time of the gas contract buy out for the rate year [redacted] the overall revenue requirement currently proposed by Puget would have been [redacted] (AURORA single water year run; PSE inputs).

Q. ARE YOU AWARE OF WHETHER PUGET CONSIDERED HEDING ITS GAS EXPOSURE AFTER THE BUY OUT OF THE TENASKA GAS CONTRACT?

A. [redacted] This quantity of gas would be sufficient to power