BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-050482

REBUTTAL TESTIMONY OF

CLINT KALICH

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION & SUMMARY

Q. Please state your name, the name of your employer, and your business address.

A. My name is Clint Kalich. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. Have you previously provided testimony in this proceeding?

A. Yes.

Q. Please summarize your rebuttal testimony?

A. My rebuttal testimony will address the power supply related adjustments proposed by Mr. Randy Falkenberg testifying on behalf of the Industrial Customers of Northwest Utilities (ICNU). I will also address one issue raised by Mr. Lazar of Public Council related to the cost to serve residential load. A table of contents for my rebuttal testimony is below:

A brief summary of my rebuttal is as follows:

1. Mr. Falkenberg's <u>hydro period</u> recommendation is inconsistent with recent decisions by this Commission and uses selective data that biases the outcome. Both water years 1973 and 1974 should remain in the normalized hydro calculation. In reviewing Mr. Falkenberg's analysis, we have found that he has used incorrect values for each of these years. When the correct values are used, neither year stands out from the rest.

2. Mr. Falkenberg's assertion that the Company does not shift enough hydro into high-value hours is mistaken. His simple model for shaping more of Avista's hydro into the highest value hours of the day ignores physical limitations of our river systems and in fact includes no recognition of plant operational constraints. It simply shifts the maximum energy level to the most valuable hours in each month, running the hydro plants at one of only two generation levels—the minimum or maximum levels identified in AURORA—and nowhere in between. The 5-year average shape used by Avista is reasonable, and in fact is essentially equal to both the 10- and 15-year shapes. Mr. Falkenberg's analysis should not be used for ratemaking.

3. The Company did not include its share of Colstrip 3&4 steam turbine upgrades (3.75 MW in 2006 and 3.75 MW in 2007) in its filing because the upgrades have not yet started. The upgrade for Unit 4, if completed as planned, will be done by mid-2006. Unit 3 would be completed by mid-2007.

4. With regard to Colstrip planned maintenance, Mr. Falkenberg incorrectly assumes that maintenance can occur during the lowest cost months of the proforma year. An initial Company oversight was corrected for the 4-party Settlement Agreement, with 10% of maintenance in each of the months of March and June, and 40% percent in both April and May. This schedule is consistent with actual historical maintenance schedules.

5. Regional power plant maintenance assumptions should not be adjusted as proposed by Mr. Falkenberg. The maintenance assumptions contained in the database are provided by the AURORA vendor. Maintenance occurs throughout the year for thermal plants, due in part to the lack of available contract crews to complete maintenance on all projects during a few months of the year. Similar to point 5 above, it is not correct to simply move all maintenance into the lowest-price months.

6. Bidding factors are designed to align forward natural gas and electricity prices, so that they reflect current relationships between the two commodity prices. Absent bidding factors and a correct representation of the relationship of natural gas and electricity, Company resources are not dispatched in a proper manner. The Company's power supply expenses therefore would not be properly calculated, absent bidding factors.

Q. Many of Mr. Falkenberg's adjustments stem from the AURORA model. Given your Company's experience with AURORA, do you have any general comments related to his testimony regarding the model?

A. Yes. The purpose of a power supply dispatch model is to reasonably and fairly determine expected operational and market conditions of the Company during the proforma period. The Company has used AURORA since April 2002. This filing is based on a model that was developed after significant review by Avista staff, the Washington and Idaho Commission staffs, and members of the Company's Integrated Resource Plan Technical Advisory Committee. The AURORA model has been thoroughly vetted during its use in the Company's 2003 and 2005 Integrated Resource Planning processes. It also has been used in support of various power supply acquisition analyses. The Company also used AURORA as the basis for its recently completed Idaho rate case, where Idaho Commission Staff took no issue with the model or its underlying assumptions. Numerous clients use this software across North America. Among their clients are leading industry consultants, banking houses, utilities, the Northwest Power and Conservation Council, the Bonneville Power Administration, and many major northwest utilities.

The AURORA model should be familiar to the Washington Commission because both Puget Sound Energy and Avista use AURORA. Commission staff has trained on the model multiple times since 2002 and has fully licensed versions of the software. Commission Staff has reviewed the Company's case and based on their participation in the Settlement Agreement, and to my knowledge, do not take issue with the AURORA model or the modeled assumptions.

The model provides a good representation of how the Company will operate its resources to serve load in the 2006 marketplace as we see it today. It shapes our hydroelectric generation into peak hours, as our historical performance indicates. The model operates our gas-fired plants when they are less costly than wholesale marketplace purchases. It also uses the wholesale marketplace to balance hour-to-hour differences between loads and resources.

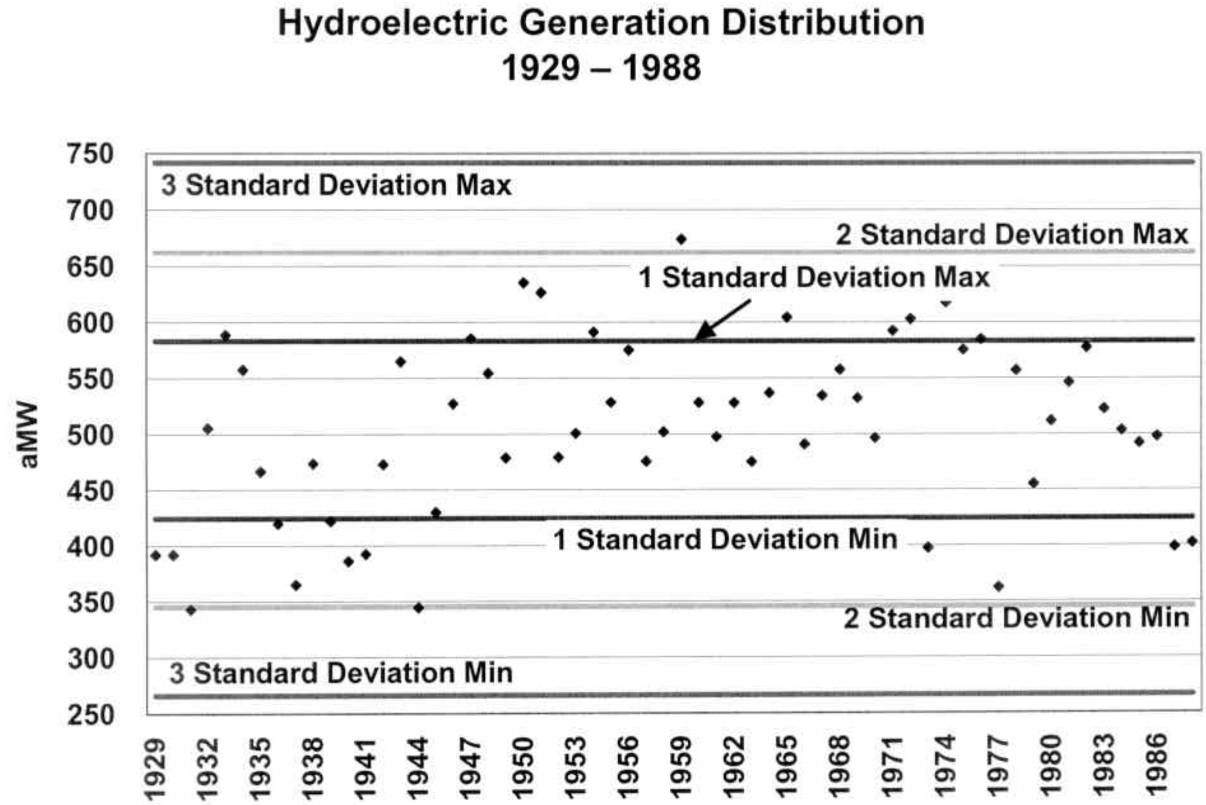
The model has a proven track record, and it properly dispatches Avista's hydroelectric and thermal resources, both to serve load and to maximize customer value in the wholesale marketplace, based on the best available information.

II. HYDRO PERIOD

Q. Please explain your concerns with the "filtering" concept proposed by Mr. Falkenberg.

A. Given what we know about the hydro record it would be inappropriate to eliminate years based on one standard deviation. Since the hydro record has been found to be normally distributed and trendless, eliminating all observations outside of one standard deviation would potentially exclude a full third of the hydro years. This contradicts statistical theory. Statistical theory defines outliers in normal and trendless distributions as those occurring beyond three or four standard deviations, not one. The use of three or four standard deviations from the mean shows that none of the water years are outliers, and none should be eliminated from the calculation. In fact, there is only one observation in the 60-year record that exceeds just two standard deviations, and it does so only slightly. See Illustration No. 1 for a visual representation of the 60-year record.

Illustration No. 1



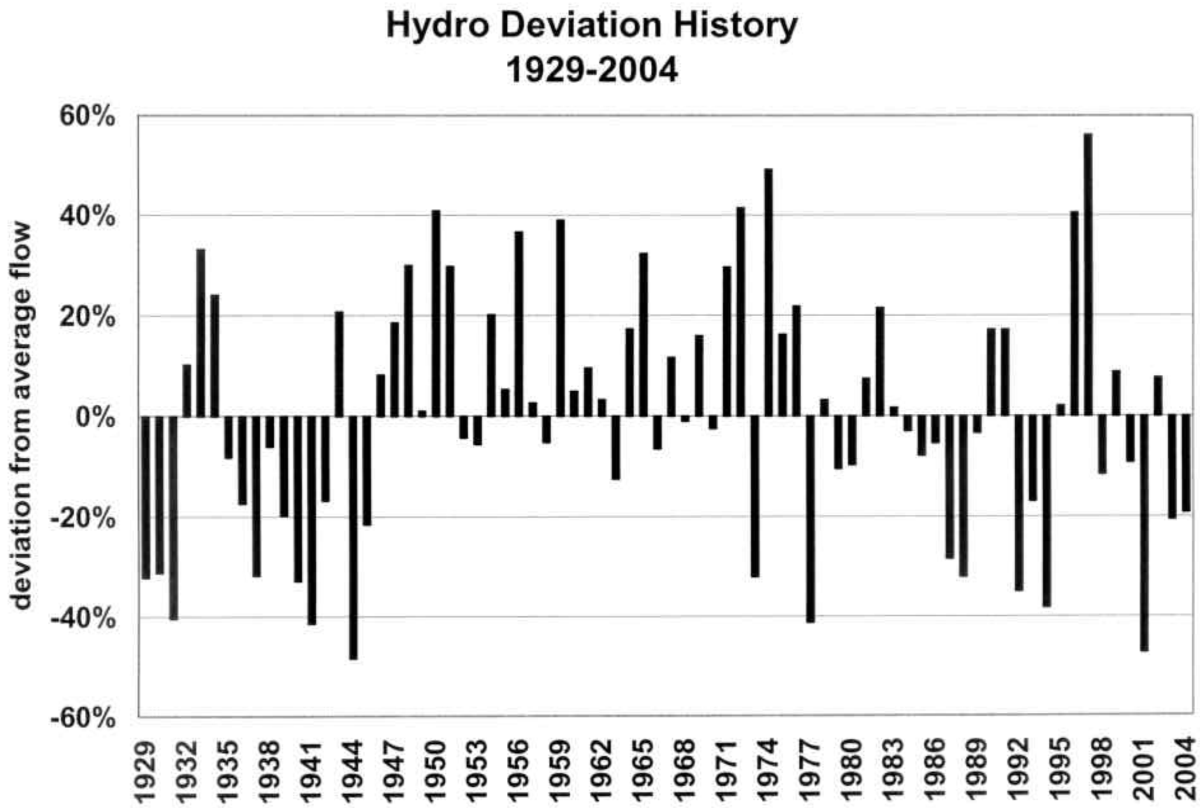
Q. Do you agree with Mr. Falkenberg's recommendation for a hydro normalization methodology?

A. No. Mr. Falkenberg recommends that the Commission use the 1939-1978 water year data filtered to remove water years more than one standard deviation beyond the mean. It is generally accepted that the hydro data is normally distributed and exhibits no upward or downward trend. Standard statistical theory dictates that all data in a trendless set should be included when making calculations. Mr. Falkenberg chooses to ignore the entire data set and focus only on data that supports his argument. He states on page 22 at line 8 that "I am not terribly concerned whether the 40-year period from 1939 to 1978 is used or the 40-year period from 1949-1988 is used, particularly if filtering is applied." The problem is that Mr. Falkenberg's approach improperly skews the hydro data for the Company by "cherry-picking" the better hydro years. Unless it can be demonstrated that a data point in a dataset is unreliable, it should remain in the dataset. Mr. Falkenberg's recommendation is to either limit the data to the better water years or filter the water years to an unreasonably narrow band contained within a single standard deviation. This leads to a biased result and should not be accepted by the Commission.

Q. Can you provide an illustration of how Mr. Falkenberg's methodology selectively chooses hydro data?

A. Yes. Page 2 of Exhibit No. 1 (CGK-2) in my direct testimony is helpful in illustrating this point, and it is reproduced immediately below for ease of reference. The exhibit shows 1929-2004 historical streamflow records. The chart was developed by weighting the stream flows for the Mid-Columbia, Spokane River, and Clark Fork River to reflect the weighted stream flow for Avista's hydro projects. The weighted streamflows then were converted into a percentage deviation from the 76-year average. Bars that are below zero are below-average hydro years; bars above zero are above-average hydro years.

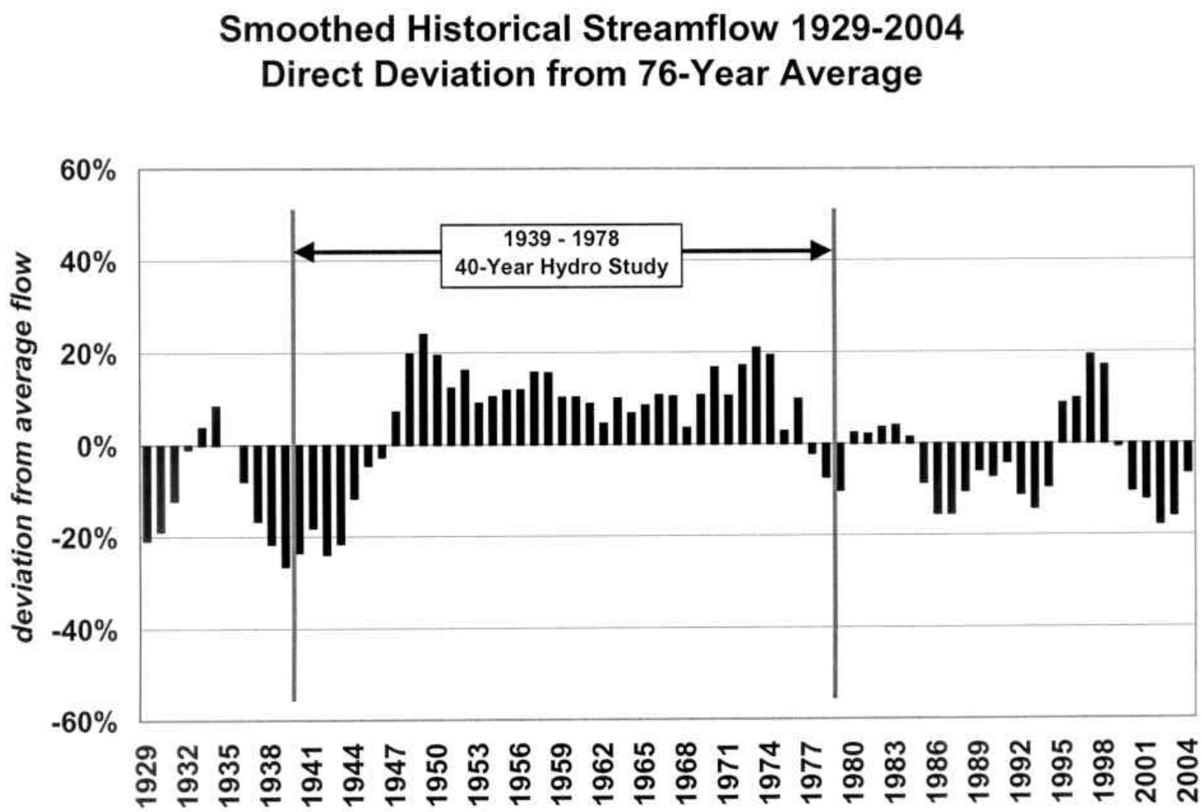
Illustration No. 2



For my rebuttal testimony, I have applied a 5-year average smoothing routine to the same 76 years of data, in order to produce the chart in Illustration No. 3 below. Using this 5-year smoothing technique, the value for 1962, as an example, is represented by the average of years 1960 through 1964; 1963 uses 1961-1965, etc. The purpose of this technique is to simply smooth out the year-to-year variations so that the deviations from the average for multi-year periods is more easily seen.

Vertical lines have also been drawn in the illustration to reflect the 1939-1978 40-year period selected by Mr. Falkenberg. This chart clearly shows that he has selected a time period that includes a disproportionate number of above-average years and fewer below-average years. His recommendation should be rejected.

Illustration No. 3



Q. Considering the quotes referenced by Mr. Falkenberg in his direct testimony beginning at page 20 line 7, do they support his case that the Company would recover its hydro variation expenses twice were all hydro years used?

A. No they do not. His first quote from our 2001 case (Docket No. UE-011595) was taken from the Commission's order that quoted Company Witness Norwood. Mr. Norwood was referring to extraordinary circumstances, and he cited as an example costs in excess of $100 million. All of the water years in the 50-year and 60-year studies fall well below this $100 million.

Q. Please comment on the Elgin quote beginning at line 24 of page 20 of Mr. Falkenberg's testimony.

A. Mr. Elgin's quote, at line 31 of page 24 states "...this settlement agreement does not deal with extraordinary circumstances that we dealt with in 2000, 2001 period…" Mr. Elgin was not referring to hydroelectric variation here, but to the market failures that led to the 2000-01 energy crisis. While low hydroelectric conditions exacerbated the problem, there were many other factors (e.g., market design, inadequate reserve margins) that created the extraordinary circumstances referenced by Mr. Elgin.

Q. Mr. Falkenberg illustrates a situation of over-collection in his Table 2. Do you concur with his results?

A. No. Mr. Falkenberg ignores the ERM in his equations. Were Mr. Falkenberg to include the ERM, total recovery would equal total costs. The ERM automatically adjusts for hydro conditions and rebates or surcharges customers. Furthermore, even apart from the ERM, to the extent the Company were to request additional rate relief based on extraordinary conditions that might be related in some way to hydro conditions, any relief granted would be based on the unique circumstances at the time, and the overall financial condition of the Company, and would not reflect an "over-collection" of costs.

Q. Mr. Falkenberg introduces a tree ring study in support of his case. Does the Company have any comments about the use of tree ring studies?

A. Yes. Mr. Falkenberg uses his tree ring study as support for his recommendation for a recent 40-year hydro period that includes more hydroelectric energy than either the 60-year case filed by Avista, or by the 50-year record used in the recent PSE case and included in the four-party Settlement Agreement. After further review, I find that the tree ring study actually supports Avista's case. At line 9 on page 24 of Mr. Falkenberg's testimony he states, "<u>the high flow periods of the 1880's</u> … tend to increase the average stream flows."(Underscore added) In other words, he is recommending a 40-year hydrological record for ratemaking that is higher than using the full record based on a loose interpretation of a tree ring study, i.e. he is suggesting that "high flow periods" be used to set normalized power supply costs. This is not reasonable, especially in light of the persistent below-normal hydro conditions the region has experienced in recent years. For Avista, four out of the last five years have been below normal.

Q. Does the four-party Settlement Agreement adopt Dr. Mariam's recommendation to use all 50 hydro years ending with the year 1978?

A. Yes. Consistent with precedent from the recently-completed PSE case, the Settlement Agreement adopts Dr. Mariam's 50 years recommendation. Furthermore, in its order in the PSE case, the Commission approved the use of the 50-year study. In so doing, the Commission observed:

> As the Commission's 1993 order states, the basis upon which it found the 40-year rolling average to be superior to other approaches was Staff's evidence in a prior case that the rolling average produced less cumulative error than other approaches. There is no evidence that Staff analyzed in those cases the statistical validity of

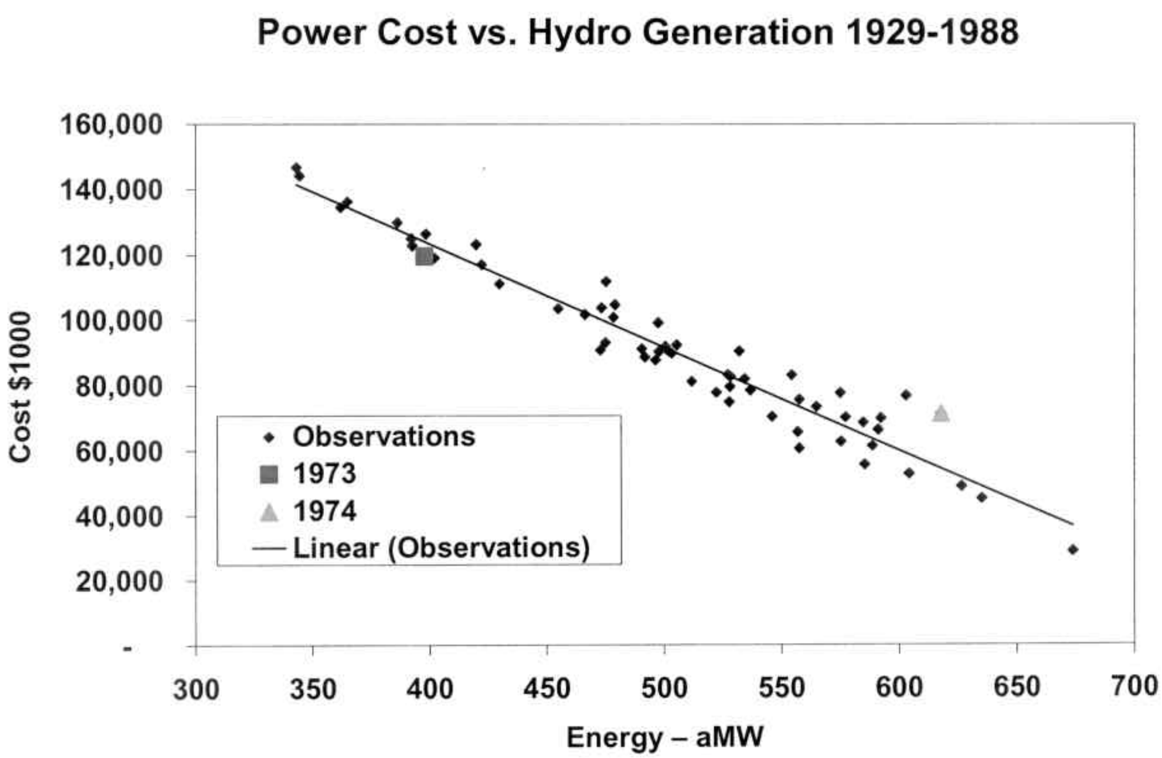
> the underlying stream-flow data as it did in this proceeding. We now have before us a detailed analysis, performed by Dr. Mariam, that confirms not only that the 50-year stream-flow data is trend-less and normally distributed, but also that there is a high degree of correlation between streamflow and hydro generation. (Order No. 06, Dkt Nos. UG-040640, UE-040641, UE-031471, and UE-032043)

The Company believes that for the purposes of settlement, this period of record is acceptable and does not suffer from the inherent under collection that would be experienced under the filtered 40-year hydro approach proposed by Mr. Falkenberg.

Q. Do you concur with Mr. Falkenberg that the 1973 and 1974 water years should be eliminated from the calculation of average power supply expense no matter which method of hydro normalization the Commission adopts in this proceeding?

A. No. In reviewing Mr. Falkenberg's direct testimony and his graph detailed on page 26, it appears that the 1973 and 1974 energy values are switched. Using the correct data set shows that these years are not "far outside the realm of reasonable results" as suggested by Mr. Falkenberg. Illustration No. 4 corrects Mr. Falkenberg's error, and shows that the values for these two years are reasonable and should not be eliminated from the average power supply expense calculation. Mr. Falkenberg also appears to have mistakenly labeled the X-axis as GWh instead of average megawatts, or aMW. The illustration also makes this correction.

Illustration No. 4



III. HYDRO SHAPING

Q. Does the Company agree with Mr. Falkenberg that it is industry standard for power production models to shape hydro to the market?

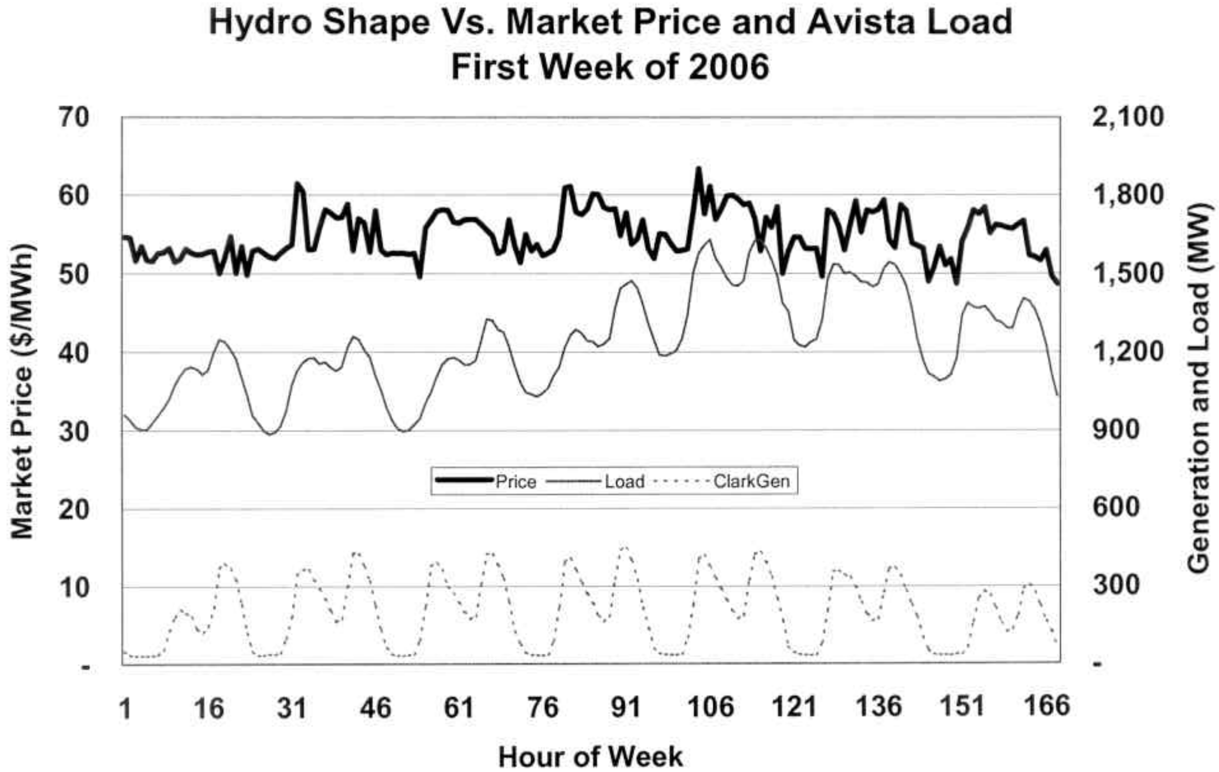
A. No. Mr. Falkenberg at page 30 line 12 states that "all of the major production cost models…model optimal dispatch of hydro." Mr. Falkenberg appears to define optimal dispatch to "establish a meaningful relationship between projected market prices and hydro operation." There are many factors beyond market prices that affect the optimal dispatch of hydro resources. He cites the PacifiCorp GRID model for example, and explains that in GRID, hydro above run-of-river is "dispatched to minimize cost." Mr. Falkenberg's Exhibit __(RJF-7) attempts to illustrate this by including an illustration of the hydro dispatch.

However, Mr. Falkenberg did not include all of the applicable text from the GRID manual. The additional text states that the GRID model distributes "discretionary energy against system load" and not the market.

Hydro dispatch essentially defines the market price in the Northwest. It is similar to the proverbial "chicken and egg" problem. Hydro is so large that re-dispatching it to chase a high market price ends up resetting the market price, leaving another market hour, that was lower in price prior to the re-dispatch, higher in price. To address this, AURORA dispatches discretionary hydro to flatten the load requirement being served by other resources. This is generally how GRID operates, too.

Market prices essentially reflect the load shape of the marketplace. To respond, Avista shapes its hydro generation to peak shave, just as AURORA and GRID do. This relationship is carried through to AURORA by the use of historical dispatch shapes. The following Illustration No. 5 shows how AURORA dispatched our Clark Fork project against our loads and the wholesale marketplace in the first week of the proforma year.

Illustration No. 5



The illustration shows that the Company dispatches its hydro with a strong bias toward the load expected during the week. The figure also explains a couple of additional things. First, contrary to Mr. Falkenberg's assertion, historical hydro patterns do a very good job of dispatching hydro for peak shaving—load shapes tend to be fairly constant over time. Secondly, the Clark Fork project is "peakier" than our load. In other words, the Company is able to ramp the project's output down in the middle of the day and night further than load alone would dictate. The "saved" energy is shifted to higher-valued peak hours to the benefit of customers.

Q. Why isn't the Clark Fork dispatched at its maximum capacity each day in the graphic?

A. The Company does not generate at the maximum capability for at least 10 reasons. I will briefly discuss each one below.

10 Reasons Limiting Hydro Capability

Load Factoring	Unit Outages
Operating Reserves	Project Characteristics
Environmental Restrictions	Market Liquidity
Load Following	Line Restrictions
Wind Integration	Reservoir Restrictions

Load Factoring refers to the general reality with hydro plants that they are energy limited. In other words, there is not enough energy (i.e., water) to generate at full capacity for extended periods. While generation might be possible at a maximum level for a short time of an hour to a few hours, the market prices generally do not differ enough to warrant choosing one hour over another hour. Therefore, dispatchers tend to operate the plant at lower capacity levels across multiple high-value hours.

Unit Outages refer to times where generators are not able to operate at full capability due to planned or unplanned times where one or more generating unit is out of service. The Company regularly removes turbines from service to perform routine maintenance. Less often, unplanned outages remove a unit from service.

Avista is required to carry *Operating Reserves* of 5% on hydro and wind generation, and 7% on its thermal generators. The Company, like its peers in the Northwest, uses hydro resources to meet a portion or all of its reserve obligations. Carrying reserves on a hydro unit means that the facility cannot generate across a portion of its capability. For example, were the

Company in a given hour to generate 1,500 MW split evenly between hydro and thermal plants, it would need to carry 90 MW of operating reserves: 37.5 MW for hydro and 52.5 MW for its thermal plants. During this hour, our hydro capability would be reduced by 90 MW.

Project Characteristics oftentimes prevent our hydro plants from generating at maximum capability. The simplest example of this is our Clark Fork River Projects. The Noxon plant has a hydraulic capacity of approximately 50,000 cubic feet per second (cfs). Cabinet Gorge, directly downstream, has a lower capacity of approximately 37,000 cfs. To generate at maximum capacity on the Clark Fork River would oftentimes require spilling over Cabinet Gorge. The economic consequences of this spill (i.e., loss of energy) greatly exceed the modest additional on-peak capacity value that could be created by spilling over Cabinet.

Plant operations are greatly affected by *Environmental Restrictions.* Over time the operational flexibility of the region's hydroelectric plants has been reduced by environmental concerns such as water quality and fisheries management. These restrictions in many cases affect the Company's ability to maximize its capacity utilization. For example, on the Clark Fork our new license obligates the utility to keep a minimum flow level of 5,000 cfs at all times. A similar restriction is present on the Spokane River. The effects are even larger on the Mid-Columbia projects.

Market Liquidity: Running a plant in surplus of one's loads in a given hour, and then buying back the energy in another hour requires a liquid wholesale marketplace. The day-ahead markets do not adequately provide for super-peak products. Real-time (i.e., spot) markets at some times can be used to leverage our hydro plant capacity, but at many times it cannot. The Company will be limited at times in the amount of hydro shaping it can perform.

The Company's ability to maximize its hourly generation is limited by *Load Following*. Load following requires the Company's generators to "follow" intra-hour changes in our load. For example, our loads swing regularly by 100 MW to 150 MW. To cover this change in a nighttime hour, we must operate one of our hydro units in a manner that it can ramp back operations as loads decrease. A project providing 150 MW of swing in an hour would only integrate to around 75 MW of "hourly capacity" due to load following in that hour.

Line Restrictions affect our ability to generate at maximum levels. At times, certain transmission lines we rely on to deliver energy from our plants to our load or to the marketplace are curtailed due to planned or unplanned maintenance.

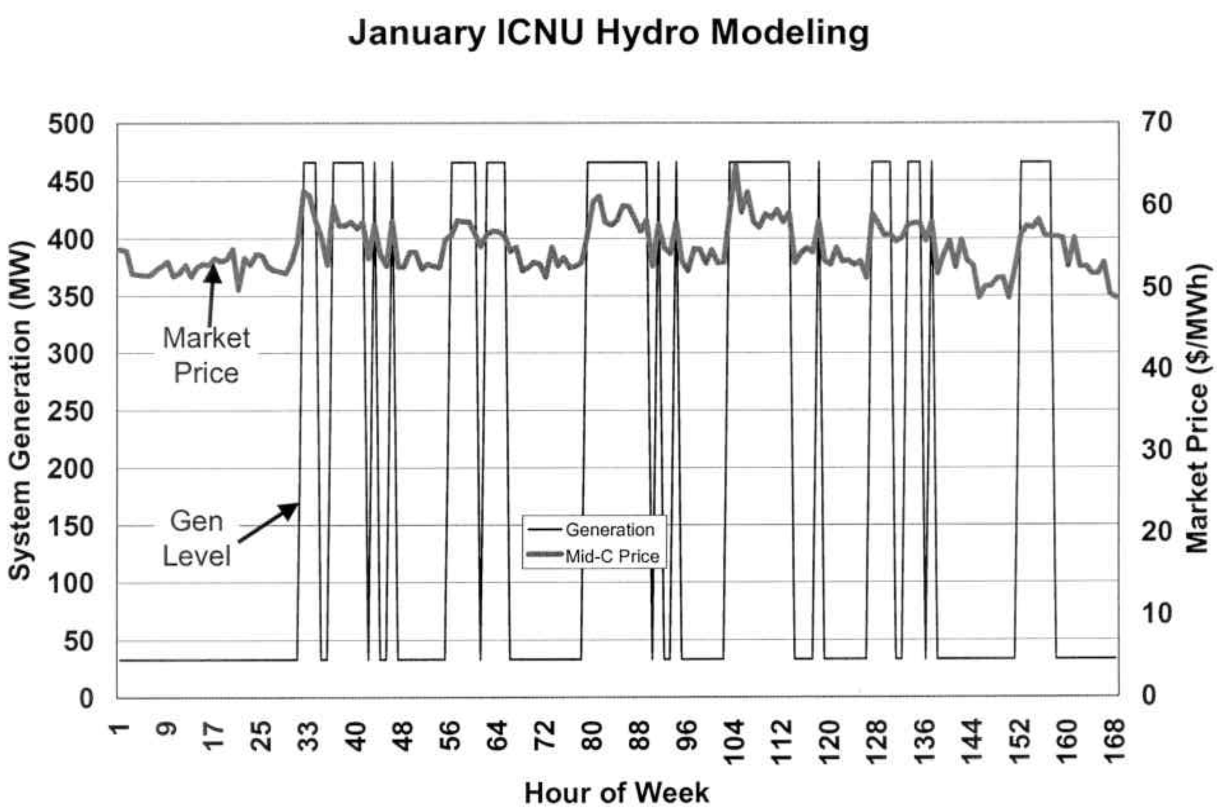
Hydro units are oftentimes used for W*ind Integration*. Wind Integration can be thought of as "negative" load following. Hydro plants are operated at points less than their optimum economic point to account for both the expected and unexpected variation in the output of the PPM Stateline Wind Energy Center output.

Reservoir Restrictions curtail hydro operations further. Many of our projects are unable to generate at maximum levels due to a need to keep reservoir elevations constant or near-constant. The requirement can be recreational in nature (e.g., keeping lake elevations constant for boaters) or contractual (e.g., Pacific Northwest Coordination Agreement restrictions on draft).

Q. Does the Company have any observations regarding Mr. Falkenberg's hydro dispatch model?

A. Yes. I have just described the complexity associated with dispatching a hydro system. It is why I believe that historical hydro operations provide the key to ensuring that future hydro operations are modeled correctly. By reviewing Mr. Falkenberg's model, I have learned that he greatly oversimplifies the analysis. To arrive at his solution, Mr. Falkenberg simply looks at the highest and lowest hydro generation hours in each separate month of the proforma period from AURORA. He then sorts prices from highest to lowest and "dispatches" our plants (all together, as if they were one resource). Across each entire month, there are only two levels of generation—minimum and maximum. Illustration No. 6 details the first week of January 2006. The rest of the month of January, and indeed all of the months, exhibit the same unreasonable shape. This assumption is not only simplistic, it has no basis in how our Company can run its system.

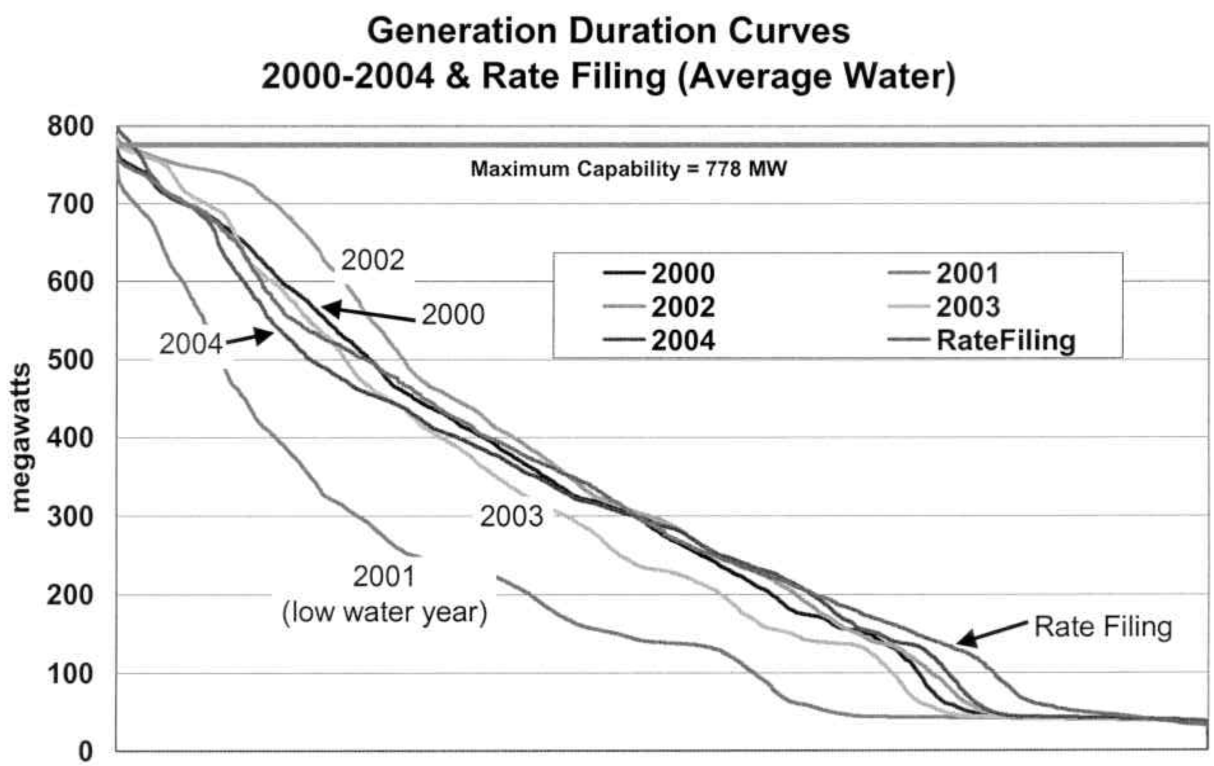
Illustration No. 6



Q. Given the complexity of these restrictions, are there other ways to confirm that Avista is properly representing the flexibility of its hydro system to the benefit of its customers?

A. Yes. Mr. Falkenberg implies in his testimony that AURORA doesn't shape enough energy into the peak hours, and that it doesn't run the plant hard enough. A duration curve analysis shows that AURORA dispatches our Clark Fork hydro plants at peak hourly levels very similar to how we have historically dispatched them. See the following Illustration No. 7.

Illustration No. 7



Q. Please review how the Company approached shaping its hydro resources for the pro forma period.

A. The Company shaped its hydroelectric generation for each river system based on a 5-year historical shape. This shape is consistent with both the 10- and 15-year average shapes. The 5-year average was selected to be consistent with the period used for other assumptions (e.g., WNP-3 contract, PGE Capacity contract). Even with the restrictions explained earlier, Avista hydro plants are, on average, more flexible than the average hydro plant factor across the Northwest. Absent using historical shapes, AURORA would shape Avista's resources to the average shape of Northwest hydro. The net result would be less on-peak generation than actually experienced in Company operations.

Q. Does the 5-year shape fairly represent the Company's hydro flexibility?

A. Yes, it does. The 5-year historical shape results in AURORA shaping 68.4% of Company hydro into the more valuable on-peak periods. This is actually slightly above the 5-year average of 67.7%. Our hydro shape has remained fairly consistent over time; the 10-year on-peak generation average is 67.7% and the 15-year average is 68.1%.

IV. COLSTRIP UPGRADE

Q. Do you agree with Mr. Falkenberg that the Colstrip Upgrades should be proformed into this case?

A. No. Although upgrades for Colstrip units 3 and 4 are planned for 2006 and 2007, the work has not yet begun. The upgrade to unit 4 is expected to be completed in mid-2006 and the upgrade for unit 3 in mid-2007.

V. COLSTRIP PLANNED OUTAGES AND OUTAGE RATE

Q. Do you agree with Mr. Falkenberg's recommendation that Colstrip planned outages should not occur across the year?

A. Yes, however, I do not agree with the assumptions made by Mr. Falkenberg to arrive at his adjustment. After filing our direct case, I discovered that we had modeled Colstrip planned maintenance as occurring across all hours of the proforma year. This was an oversight that we corrected and included in the Settlement Agreement. Colstrip maintenance actually occurs during various lower-cost months of the year depending on a number of factors, including the availability of labor to perform the maintenance, specific operating concerns at the plant, the extent of maintenance required, and market conditions.

Colstrip planned maintenance historically has occurred from March through June, with approximately 10% occurring in each of March and June, and 40% occurring in each of April and May. During settlement negotiations, the Company corrected this oversight and decreased its overall revenue requirement by $481,275 (WA allocation). The four-party Settlement Agreement reflects this figure. Mr. Falkenberg's value is too high by a factor of nearly four ($1.643 million WA allocation). Mr. Falkenberg arrives at his adjustment by scheduling Colstrip maintenance "to coincide with periods of lowest wholesale prices." This assumption is incorrect based on actual historical schedules for required maintenance and would significantly overstate the correction.

Q. Do you agree with Mr. Falkenberg's position on adjusting the "Colstrip Outage Rate?"

A. No. The Colstrip plants are 20 years into their 35-year design life. Some modest performance degradation is not surprising for plants nearly 60% through their lives. Avista has a 15% minority ownership position in the Colstrip plants, which limits to some degree our ability to direct operations and maintenance. However, the Colstrip plants have performed over 20% better than the average U.S. coal plant (80% vs. 66% capacity factors).[1] Colstrip also has performed modestly better (80% vs. 77%) than the average of all coal plants in the Western Interconnect. In summary, Colstrip has not performed poorly as Mr. Falkenberg suggests.

The Company uses five-year average values for many of its operations that vary over time including: thermal outages, planned maintenance, small PURPA resource output, WNP-3 contract performance, and the PGE Capacity contract. The Company sees no reason to depart from this methodology, especially in light of Mr. Falkenberg's mischaracterization of Colstrip's performance.

Q. Mr. Falkenberg asserts at page 3 of his direct testimony that the AURORA database overstates power supply costs by the "use of unrealistic outage schedule assumptions for other regional plants." Do you agree with his position?

A. No. To support his position Mr. Falkenberg simply states, at page 38 beginning at line 13, that "the planned outage rate modeling is questionable" and that outages "do not appear coordinated with the market price results of the model." He then mistakenly concludes that all outages can always be timed to occur during the least-cost months of the year.

[1] Using the latest 5-year (1999-2003) data available from the Energy Information Administration.

Mr. Falkenberg provides no supporting documentation beyond his opinion that outage schedules are incorrect in AURORA. Avista purchases AURORA from EPIS, Inc., an industry leader in electricity market modeling software. EPIS Inc. is one of a handful of leading electricity market modeling software developers and is an expert in this arena. Numerous clients use this software across North America. Among their clients are leading industry consultants, banking houses, the Northwest Power and Conservation Council, the Bonneville Power Administration, and many major northwest utilities.

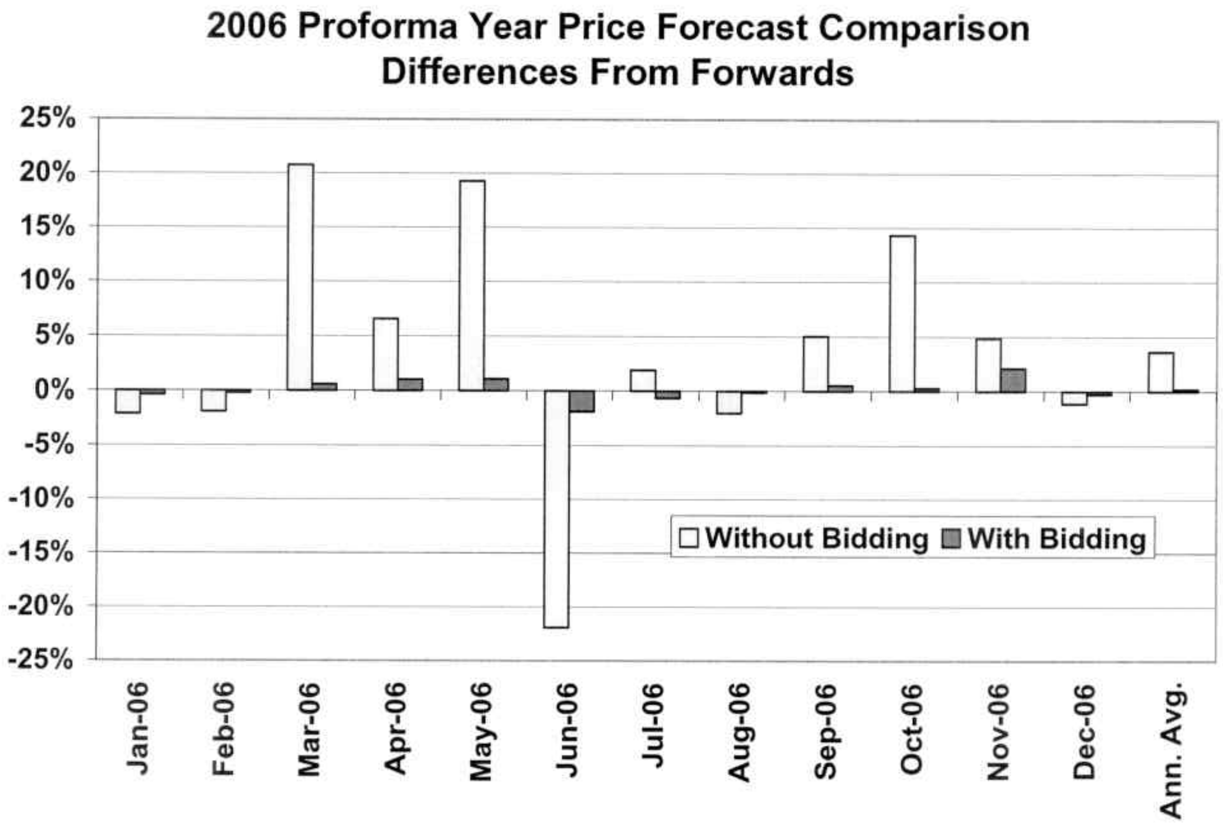
The AURORA software package contains a base set of resource assumptions, including plant maintenance and outage data. While each specific plant might vary somewhat from its actual operation, the marketplace is modeled in a manner that fairly represents its behavior. In addition, as noted earlier, contract crews are not available to conduct maintenance on all thermal projects across the Western Interconnect during just a few months of the year.

VI. BIDDING FACTORS

Q. Does Avista agree with Mr. Falkenberg's recommendation that bidding factors be eliminated in the power supply model?

A. No. Bidding factors are designed to more closely align forward natural gas market prices and wholesale electric prices, which in turn ensures that Company resources are operated, as we would expect them to, given what is known about the 2006 marketplace today. The results, with and without bidding factors, are compared to the average forward price curve in Illustration No. 8 below. The AURORA run with bidding factors clearly represents the forward marketplace more closely than the AURORA run without bidding factors. In fact, the bidding factors logic was included in the model for that very purpose, i.e., to ensure that the market prices in the AURORA model reflect the actual forward markets.

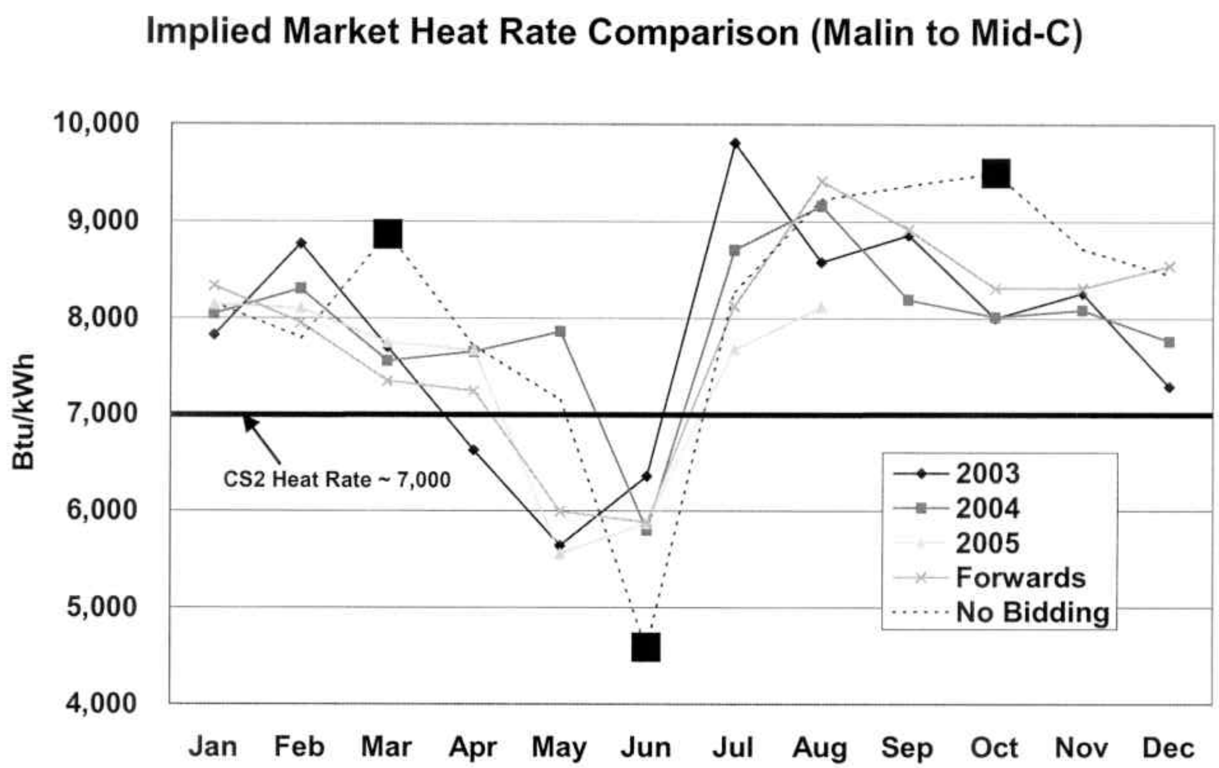
Illustration No. 8



Q. Doesn't the fact that the months average to approximately the right price mean that proforma power supply expenses are correct absent bidding factors?

A. No. It is important to get month-to-month relationships correct. Illustration No. 9 compares AURORA prices absent bidding factors with historical prices. The illustration shows that the no bidding logic case has three outlying months relative to history, as shown with large black squares.[2] Where the relationship between natural gas and electricity are not properly aligned, as in these three months, the power supply model will not estimate proforma power supply expenses correctly.

Illustration No. 9



As I explained earlier, the bidding factors logic was included in the design of the model to properly align market prices, and it is appropriate for it to be used on this case.

[2] The implied market heat rate is calculated by taking the market price and dividing it by the natural gas price and multiplying by 1000. This value is synonymous with "spark spread", and is equal to the spark spread times 1000.

Q. Do you agree with Mr. Falkenberg that forward prices do not necessarily represent spot market prices the Company might experience during the pro forma year?

A. While actual prices may not ultimately turn out to match the current forward prices, the current forward market prices represent the best information available for future market conditions. The Commission recognized the importance of using forward prices in the recently completed PSE case—Docket No. UE-040641—and ordered a three-month averaging of forward market values. The Settlement Agreement reflects the use of a three-month average of natural gas and electricity prices, consistent with the Commission's prior order.

Q. Given his concern with forward market prices for power, does Mr. Falkenberg take issue with the Company's use of forward prices for natural gas?

A. No. Mr. Falkenberg did not explain why he is comfortable with natural gas prices being set based on forward curves, but not electricity prices. This is inconsistent, as natural gas prices ultimately set the market price for power since gas-fired plants are on the margin during most of the pro forma year.

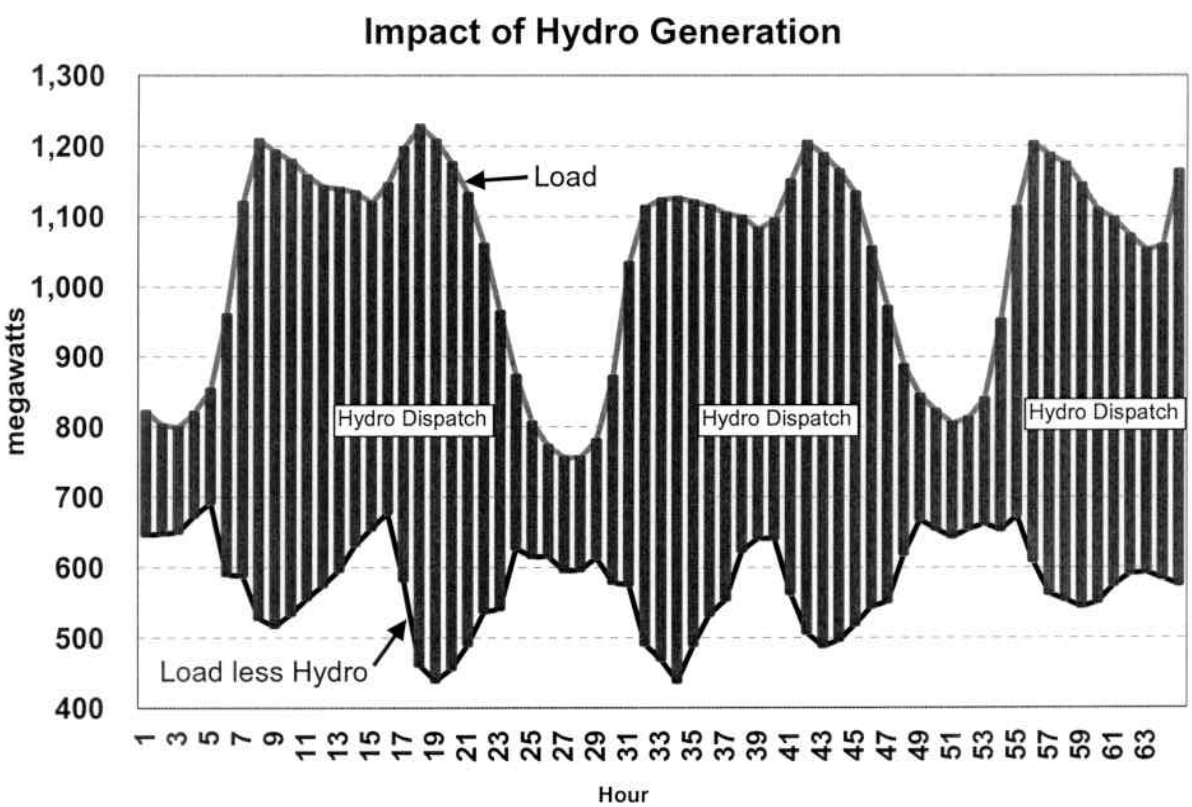
VII. COST TO SERVE RESIDENTIAL LOAD

Q. Are there additional issues in this case that you would like to address?

A. Yes. Mr. Lazar, beginning on page 13 of his direct testimony, presents his position that the Company should further invert its residential rate schedule to reflect the power supply expenses incurred by the Company to serve the loads in rate blocks two and three. Mr. Lazar's recommendation to further invert our residential rate schedule is inappropriate for Avista's system and the Northwest.

The Northwest is an energy-constrained marketplace dominated by hydroelectric resources. Resources generally are built to provide base-load energy, not peaking capacity. The hydro system is primarily responsible for providing peak capacity. In contrast, much of the rest of the country is thermal-based and provides peak generation from thermal-sourced plants, oftentimes peaking gas plants. In the case of Avista and the Northwest generally, thermal plants are base-loaded across the days, weeks, and months, with hydro plants serving peak load periods. Illustration No. 10 shows how hydro generation is used to greatly reduce the peak loads on our system. For the illustration I have displayed three days in mid-November from the Proforma period under average water conditions.

Illustration No. 10



The top line in the graph represents Avista's retail load over the course of three days. The bottom line on the graph shows the same retail load after being reduced by the available hydroelectric generation. The result, as shown by the bottom line, is a more flat load to be served by thermal resources, which generally are run around the clock.

The graph shows that during the on-peak periods of the day (morning and evening), there is more than enough hydro generation to cover these peak loads, i.e., during the morning and evening peak periods the load, net of hydro generation, is less than for other hours of the day.

In addition, Illustration No. 5 presented earlier in my testimony explained how the Company shapes its hydro generation to serve peak loads.

The best measure of a utility costs in today's marketplace, and in fact the key driver in resource acquisition, is the wholesale marketplace. Illustration No. 11 compares both the peak and flat, or average Mid-Columbia prices, for the proforma year as a whole, for the winter months of the proforma period, and for the summer months of the proforma period.[3]

Illustration No. 11

2006 Proforma Mid-C Prices

Month	On-Peak (cents/kWh)	Flat (cents/kWh)	Differential (cents/kWh)
2006 Average	4.84	4.59	0.25
Winter Months	5.36	5.16	0.20
Summer Months	4.77	4.47	0.30

As the illustration shows, the peak difference from the average price in 2006 is a mere 0.25 cents per kWh. This compares to Mr. Lazar's recommendation on page 16 of his direct

[3] Winter months are defined as Nov-Feb. Summer months are defined as Jun-Sept.

testimony that prices differ across the blocks by more than 2.02 cents per kWh. On this view, Mr. Lazar has overstated the need for residential rate block differentials by as much as a factor of eight. The results are similar in both the winter and summer months where space-conditioning loads occur.

Another approach is to view the differentials between the space-conditioning periods (summer and winter) and the average market price, with the thought that seasonal load differentials should be reflected in rate design. As the winter differential is the largest, I will consider it here. The flat annual average price equals 4.59 cents per kWh in Illustration No. 11. This compares to the flat winter price of 5.16 cents per kWh. The difference is 0.57 cents per kWh. On this measure, Mr. Lazar's range is more than three times what the marketplace would support.

VIII. SUMMARY

Q. Will you please summarize your testimony?

A. Yes. My testimony has addressed seven adjustments proposed by Mr. Falkenberg on behalf of ICNU. The 50-year continuous hydro period (1929-78) contained in the Settlement Agreement is reasonable in the context of a settlement with the parties, and is consistent with the WUTC's recent order in the Puget Sound case. Mr. Falkenberg's adjustment should be rejected.

The hydro shaping model developed by ICNU incorrectly allocates the capacity of our hydroelectric plants. My testimony explains that using a five-year average of weekly hydro generation shapes allows 68.4% of all hydro energy into the high-value heavy-load hours. Looking back further at the 10- and 15-year averages provides essentially the same result, indicating that the relationships have been consistent over time. Additionally, I have shown with a generation duration curve that our hydro plants are dispatched essentially as they have been over the past five years. Finally, Mr. Falkenberg's model greatly oversimplifies hydro dispatch and assumes that a maximum amount of all hydro energy can be dispatched into the higher value hours, and doesn't account for the 10 dispatch issues I identify in my testimony. Mr. Falkenberg's adjustment should be rejected.

The Colstrip adjustments advocated by ICNU are not reasonable. First, it is not appropriate to include Colstrip upgrades at this time. Second, the Colstrip maintenance adjustment was corrected in the four-party Settlement Agreement after the Company discovered it. It is not reasonable to simply shift all of Colstrip's maintenance to the lowest-cost month of the year. Maintenance has not occurred this way in the past, and is not expected to occur in this manner in the future. Finally, Colstrip has performed better than both average U.S. and Western Interconnect coal plants. It is not reasonable to depart from a five year averaging of Colstrip performance. Mr. Falkenberg's adjustments should be rejected.

Similar to his approach on Colstrip, Mr. Falkenberg advocates shifting all coal plant maintenance across the Western Interconnect into the lowest-cost month of the year. This proposal ignores factors such as maintenance crew limitations. Mr. Falkenberg's adjustment should be rejected.

Bidding factors ensure that market conditions and price relationships are reasonable. Bidding factors make forward natural gas and electricity prices match up with the best available information at this time—the three-month average of 2006 forward prices. Mr. Falkenberg's adjustment should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.