Exh. CGK-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DIRECT TESTIMONY OF

CLINT G. KALICH

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

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

Q. In what capacity are you employed?

A. I am Senior Manager of Resource Planning & Power Supply Analyses in the Energy Resources Department of Avista Utilities.

Q. Please state your educational background and professional experience.

A. I graduated from Central Washington University in 1991 with a Bachelor of Science Degree in Business Economics. Shortly after graduation, I accepted an analyst position with EES Consulting, Inc., a Northwest management-consulting firm located in Bellevue, Washington. While employed by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the area of electric utility management. My specific areas of focus were economic analyses of new resource development, rate case proceedings involving the Bonneville Power Administration, integrated (least-cost) resource planning, and demand-side management program development. In 1995, I joined Tacoma Power, where I provided key analytical and policy support in the areas of resource development, procurement, and optimization, hydroelectric operations and re-licensing, unbundled power supply ratemaking, contract negotiations, and system operations.

In 2000 I joined Avista as a Senior Power Supply Analyst supporting the electric side of Avista business. I was promoted to Manager of Resource Planning and Power Supply Analyses in 2002. In 2022 I was promoted to Senior Manager, Resource Analysis – Energy

Supply, and similar responsibilities on the natural gas side of the business were added to what I had been managing for the electric side of the business. Throughout my Avista career I have worked or managed staff in the areas of resource analysis, production cost and optimization modeling, resource procurement, integrated resource planning, and rate case proceedings. Much of this work, and management direction, involved resource dispatch modeling of the nature described in this testimony.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will list key components of the Power Supply methodology developed collaboratively in workshops completed as part of Order No. 07 in Dockets UE-170485 et. al. My testimony then will describe key inputs and assumptions driving power supply costs through the methodology—including loads, outages, natural gas, and electricity prices—and provide a comparison to the current level of authorized net power supply expense (NPE). It will detail our methodology to reflect value from participation in the EIM intra-hour market. Also supported will be an adder to adjust the unprecedented overstatement our electric generation fleet's value in the pro forma.

With this as necessary context, I will provide further evidence in supplement of Company witness Mr. Kinney's testimony describing the importance of, and need for, eliminating Energy Recovery Mechanism (ERM) deadbands in favor of a single 95% pass-through of cost variance from authorized levels to customers. Finally, this testimony will identify and explain the specific values proposed as pro forma adjustments to the 12-month ended June 30, 2023 test period power supply revenues and expenses, including the Retail Revenue Credit used in Energy Recovery Mechanism (ERM) deferral calculations.

A table of contents for my testimony is as follows:

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring exhibits marked Exh. CGK-2C through Exh. CGK-6 as shown in Table No. 1 below. All are contained within one workbook in my workpapers. All formulas and links remain intact for ease of reference. Information contained in these exhibits was prepared by me or at my direction.

<u>Table No. 1 – List of Exhibits</u>

Exhibit Name	Description
Confidential Exh. CGK-2C	Dispatch Model Results
Exh. CKG-3	Pro Forma and Adjustment Summary
Exh. CGK-4	Pro Forma Line Descriptions
Exh. CGK-5	Market Purchases and Sales, Plant Generation and Fuel Cost
Exh. CGK-6	Proposed Power Supply Base for ERM
Exh. CGK-6 RY2	Proposed Power Supply Base for ERM without Colstrip

II. PORTFOLIO MODELING

Q. What are the primary components of the power supply modeling methodology?

A. The basis for the Company's proposed NPE uses a methodology agreed to as part of Docket UE-170485. Avista began using this "Power Supply Methodology" as the basis for power supply modeling in Avista's 2020 General Rate Case. In summary, the Power

Supply Methodology covers seven areas affecting power cost modeling:

1. Modeling Tool
2. Source of Market Prices
3. Pricing Methodology
4. Hydro Conditions
5. AECO-to-Malin Transportation Contract
6. System Input Data
7. Data Updates 60-Days Prior to Rates Going into Effect

Each area is described in detail in my prior testimony (see Dockets UE-220053 et. al.); no changes are included in this case except for how the Modeling Tool (Aurora) dispatches our system on a 5-minute intra-hour basis, explicitly capturing the value of the California Energy Imbalance Market (EIM).[1]

Q. Does this filing reflect the value of EIM to customers?

A. Yes. This case was modeled in 5-minute sub-hourly increments to capture the additional benefits of EIM.

Q. Please explain how prices are shaped in the Model to include EIM value.

A. Monthly forward heavy load hours/light load hours (HLH/LLH) electricity prices are first translated to hourly prices, and monthly forward natural gas prices are shaped to daily prices. The more granular prices are created by breaking out the periods algebraically and shaping them based on actual test year prices. Weekdays are shifted as necessary to align the test and rate years. This means that if the rate year begins on Tuesday, but the test year begins on Monday, the test year data will be shifted one day so that the weekdays line up. Should the historical test year contain volatility from extraordinary events not expected to occur in the normalized test year, an adjustment removes such events, and the filing

[1] Avista used version 14.2.1091.0 for this case.

documents the adjustment.[2] The calculations provide hourly electric prices for the pro forma period, such as 744 hours for the Mid-C in January, that are then translated to 5-minute intra-hour prices using a methodology I describe later in testimony. AECO and Malin natural gas prices are calculated similarly using the Malin daily price shapes, as natural gas spot market trades are reported as a single price for each day.

Q. Do input prices include the impact of the Energy Imbalance Market (EIM)?

A. Yes. The use of more granular 5-minute intra-hour prices in the Model reflect the dispatch flexibility of our resources in an EIM environment. The intra-hour prices are based on a consultant-developed methodology correlating the relationship between hourly Powerdex and intra-hour EIM market prices.

Q. Please describe how this correlation was done.

A. Avista retained Los Angeles-based utility consulting firm Borismetrics to correlate: 1) 5-minute EIM and hourly Mid-C power prices, and 2) hourly variable energy resources (VER) datasets to 5-minute datasets.[3] Borismetrics performed analyses of the historical statistical relationships of hourly 5-minute average data for Northwest market prices, wind generation, and solar generation with each corresponding actual 5-minute period in the same hour. Specific to representing EIM prices, seasonal, weekly, and diurnal patterns were examined using more than two years of historical 5-minute EIM CAISO results and comparing those to hourly Mid-C index prices as recorded by Powerdex.[4] These datasets

[2] There were no extraordinary adjustments in this filing.
[3] borismetrics.com
[4] See powerdexindexes.com. Avista, along with its peer utilities, reports results of its hourly commodity energy transactions in the wholesale marketplace. Powerdex compiles this information and provides, for a fee, an overall market index representing hourly indexes for various points in the WECC.

enable historical ratios between 5-minute intervals and average hourly levels by month, hour and weekday/weekend that are used to create 5-minute EIM electricity prices from hourly Mid-C prices. The two datasets were generally similar and highly correlated at the hourly level. This effort resulted in a Mid-C pricing model creating 5-minute input prices for use in intra-hour modeling. The Borismetrics models and data for EIM electricity prices are included in my Confidential workpapers because of provisions contained in our Powerdex data services contract.

Q. How were variable energy resources (VER) handled for sub-hourly modeling?

A. Borismetrics conducted similar analyses on VER generation, where actual 5-minute interval data was statistically analyzed and compared over a 13-month historical period to actual hourly values for Palouse Wind, Rattlesnake Wind, and Adam-Nielson Solar. The 13-month period was selected because Avista had complete data for the three major VER projects. The result was a model translating hourly generation to 5-minute interval data based on historical ratios, including seasonal and diurnal patterns. Individual models translating hourly generation to 5-minute interval generation were created for each VER project: Palouse Wind, Rattlesnake Wind, Clearwater Wind and Adam Neilson Solar. Because Clearwater Wind is not yet in service, the model used to create 5-minute generation profiles for Rattlesnake Wind was used based on hourly generation profiles from the vendors. Borismetrics' work correlating hourly and 5-minute VER generation are provided in my workpapers non-confidentially.

Q. Please further describe how Avista's resources are dispatched in the Model.

A. In each period where the Northwest market price is higher than the per-MWh cost of operating one or more Avista resources, the Avista resource, or resources, is dispatched. Load not served by Avista resources in the period, if any, is served by the Northwest market, with a cost equal to the input market price. If dispatched Avista resources exceed Avista's load in the period, the extra power displaces a portion of the market serving the broader Northwest load, and this revenue is credited to lower pro forma power supply costs. In this way, Avista's resources and loads are valued at electricity prices input to the Model.

Q. Specific to the Pro Forma Period, what prices are being utilized in the Model (Items No. 2 Source of Market Prices and No. 3 Pricing Methodology)?

A. Following the agreed-upon pricing methodology, forward electricity and natural gas prices use the three-month average (approximately 60 market settlement days) of Intercontinental Exchange (ICE) prices from May 16, 2023 through August 15, 2023, the date range up to the point where Avista began modeling its costs for this case. Prices are initially shaped hourly for electricity and daily for natural gas, reflecting how these spot markets traded in the test year and will trade in the pro forma year. For example, if during the 12-months ended June 30, 2023, the Northwest electricity price in the first hour of January is 90 percent of the average January price in the test year, then the input price to the Model for that hour is equal to 90 percent of the January 2025 forward price. Similar math is performed for natural gas, but because the spot market for natural gas is based on daily pricing, the shape is done daily using the Malin daily test year shape. To reflect the additional flexibility of the EIM market, hourly electricity prices resulting from the methodology described here are translated to 5-minute prices using Borismetrics models described earlier in testimony. Backup for the price calculations can be found in my workpapers.[5] Table No. 2 below details the prices input into the Model affecting our resources.

<u>Table No. 2 – Modeled Prices at Key Hubs</u>

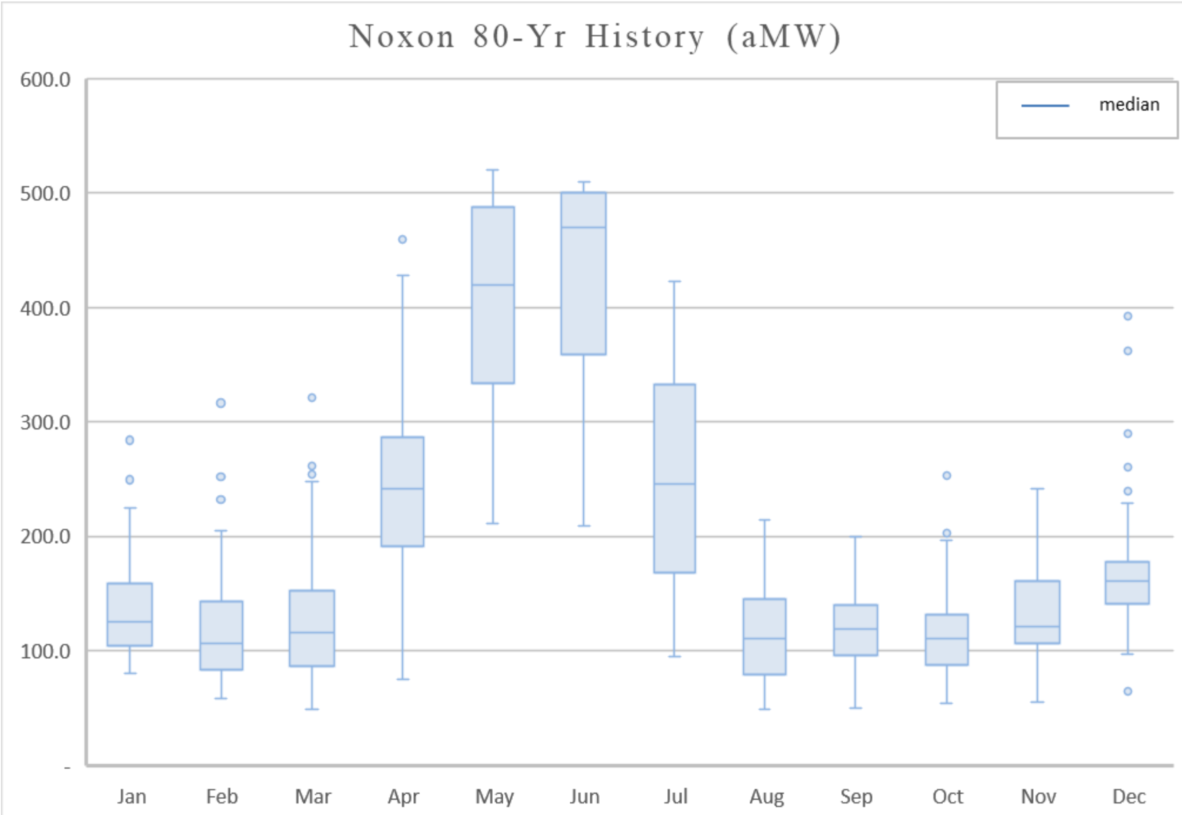
Period	AECO ($/dth)	Malin ($/dth)	Mid-C LLH ($/MWh)	Mid-C HLH ($/MWh)
Jan-25	3.14	6.25	83.66	91.18
Feb-25	3.15	5.99	75.63	80.20
Mar-25	2.86	4.39	57.40	59.75
Apr-25	2.57	3.32	46.51	43.69
May-25	2.47	3.23	42.16	41.92
Jun-25	2.50	3.42	26.95	36.09
Jul-25	2.55	3.77	53.22	106.44
Aug-25	2.59	3.82	76.53	138.13
Sep-25	2.66	3.77	66.27	113.14
Oct-25	2.79	3.78	80.57	79.41
Nov-25	3.10	4.67	86.06	85.88
Dec-25	3.41	5.77	95.58	96.87
Average	2.82	4.35	65.88	81.06

Q. Please provide further information on Item No. 4, Hydro Conditions.

A. In accordance with the agreed-upon Power Supply Methodology, a single year of median monthly values from the eighty-year water record is determined using the full hydro record for each project. The illustration below depicts the 80-year record and median values for our largest hydroelectric resource, Noxon Rapids, on the Clark Fork River. Supporting data for the chart, as well as similar data and charts for our other hydro plants and Mid-C contracts are in my workpapers.

[5] See Kalich workpaper: NaturalGas_Elec_Prices.xlsx.

Illustration No. 1 – Monthly Median Water at Noxon Rapids



Q. How does the Model operate Company-controlled hydroelectricity generation resources?

A. To account for actual flexibility of Company hydroelectricity resources, Avista develops individual operational logic for each river system in the Model. This separation ensures that inherent flexibility is credited to customers in the pro forma exercise using generation profiles for <u>each</u> river system closely matching its five-year average through 2022.

Q. Please compare the operating statistics from the Model to recent historical hydroelectricity plant operations.

A. Over the pro forma period, the Model generates 66% of Clark Fork generation during on-peak hours. Since on-peak hours represent only 57% of the year, this demonstrates a substantial shift to the more expensive on-peak hours and approximates the five-year average of on-peak generation at the Clark Fork. Avista ensures similar shaping results by river system for each month. Data supporting these calculations are in my workpapers.[6]

Q. How are reserves modeled?

A. Avista does not implicitly represent reserves in the Model, though we employ two methods to reflect reserves. The first is the use of five-year hydro shaping. This shape reflects the operations of our hydro plants over time and how they are impacted by providing reserves. The second method is limiting the dispatch of our Northeast and Rathdrum natural gas plants, just as our operations and trading teams do in their actual business. I will discuss the impacts reserves place on our thermal fleet later in my testimony.

Q. Please provide further information related to Item No. 5, AECO-to-Malin Transportation Contracts.

A. Avista's thermal operations rely on long-term firm transportation contracts from the AECO basin in Alberta, Canada, to Kingsgate at the U.S. Border, and from Kingsgate to multiple points south, terminating at the Malin basin located in Oregon.[7] The Power Supply Methodology calls for the Model to dispatch Avista's electric generation plants using a "landed" natural gas price based on Malin. The landed price is derived in most cases by discounting the Malin forward price with fuel loss, delivery, and tax charges associated with delivery to each plant. A spreadsheet model reduces natural gas fuel cost from the Model's dispatch due to much lower (>30% of Malin) AECO prices up to the contractual rights Avista

[6] See Kalich workpapers: Hydro History_ClarkFork.xlsx, Hydro History_Spokane.xlsx, Hydro History_MidC.xlsx.
[7] Avista has approximately 61,000 dekatherms per day of natural gas transportation rights from AECO. Lancaster and Coyote Springs 2, our efficient combined cycle gas turbines when operating together exceed this amount. Total natural gas consumption across the fleet during peak days approaches a demand level of twice our contractual rights from AECO.

holds from AECO and Kingsgate. As with previous cases, our natural gas-fired plants continue using this methodology. In addition, surplus transportation capacity not used for dispatch is valued in the pro forma using the spread between AECO and Malin, consistent with overall market prices. This spreadsheet model is included in my workpapers.

Q. Please expand on Item No. 6, System Input Data.

A. The Power Supply Methodology continues past practice, namely using five-year averages for forced and planned maintenance outages, hydro shaping, and variable and small (e.g., PURPA) contract generation levels, and various other data that are not known with near certainty due to year-to-year variability. Various other miscellaneous expenses, such as broker fees, transmission revenues, etc., also use a five-year average when five years of data is available. For plants where two maintenance cycles exceed the five-year window (i.e., Colstrip), an average of outage rates over the past two cycles is used. Finally, extraordinary events are removed from the averaging described above when adequate justification for such removal exists.[8] Backup for such calculations are included in my workpapers provided to the parties in this case.

Q. Please provide further information on Item No. 7, Data Updates 60-Days Prior to Rates Going in Effect.

A. As outlined in the Power Supply Methodology, certain power supply model data are updated 60-days prior to rates going into effect to lessen variability and improve accuracy, as detailed below:

- Wholesale natural gas and electricity prices
- Non-gas fuel prices (i.e., wood, coal)
- Incremental short-term contracts for natural gas and electricity

[8] No such extraordinary adjustments were made for this filing.

- Power and transmission service contract affecting the rate year

These updates provide a refresh of natural gas and electric market prices, non-natural gas fuel prices where such prices are the result of a contract, the addition of all new incremental contracts with terms less than one year affecting the pro forma period, and any known rate changes to power and transmission service contracts in the filing.

Q. Is the Company planning to file a 60-day update consistent with the Power Supply Methodology?

A. Yes. On or about October 15, 2024, Avista will provide the Commission and parties with a 60-day update that updates wholesale natural gas and electricity prices, non-gas fuel prices (i.e., wood, coal), incremental short-term contracts for natural gas and electricity, and power and transmission service contract affecting the rate year, consistent with the Power Supply Methodology.

Q. Please explain how the current case modeling the system intra-hourly values EIM benefits for customers.

A. Modeling in this case values EIM by offering 5-minute intra-hour dispatch flexibility. As an example, an average hourly price of $50 per MWh is comprised of twelve 5-minute pricing intervals both lower and higher than $50. A hydro resource in an hourly model would generate at a single operating level and receive $50 times the MWh generated, or $5,000 for 100 MW. With intra-hour modeling, the same number of MWh can be generated by the hydro resource, but such generation can occur at higher levels for shorter periods of time, resulting in higher value for customers. Below is a simple example to illustrate the concept, showing how the same hourly average generation at the same hourly average price enables the hydro resource in a 5-minute intra-hour dispatch model to generate $1,500 more value for customers than in an hourly dispatch model.

Table No. 3 – Hourly vs. Intra-Hourly Dispatch Value Example

Pre-EIM Hourly Dispatch Value				EIM Intra-Hour Dispatch Value				
Hour	Price ($/MWh)	MW	Value ($)	Hour	Period	Price ($/MWh)	MW	Value ($)
1	47.50	100	396	1	00-05	20.00	0	-
1	47.50	100	396	1	05-10	25.00	0	-
1	47.50	100	396	1	10-15	30.00	0	-
1	47.50	100	396	1	15-20	35.00	0	-
1	47.50	100	396	1	20-25	40.00	0	-
1	47.50	100	396	1	25-30	45.00	0	-
1	47.50	100	396	1	30-35	50.00	200	833
1	47.50	100	396	1	35-40	55.00	200	917
1	47.50	100	396	1	40-45	60.00	200	1,000
1	47.50	100	396	1	45-50	65.00	200	1,083
1	47.50	100	396	1	50-55	70.00	200	1,167
1	47.50	100	396	1	55-60	75.00	200	1,250
Average	47.50	100	396	Average		47.50	100	521
Total			4,750	Total				6,250
Value Gain ($)								1,500

Q. Has the Company quantified the incremental value of intra-hour modeling to customers in this case?

A. Yes. In Dockets UE-220053, et. al., the Company was not prepared to model power supply costs on a 5-minute granularity. We instead included in the pro forma an annual system benefit based on a study by Economic and Environmental Economics (E3). For this case, however, the Model is run at 5-minute intervals with the commensurate incremental dispatch value credited to customers.

With the Model now reflecting 5-minute granularity of the EIM marketplace, defining the value attributable to customers from intra-hour EIM modeling relative to hourly modeling used in previous cases is necessary. Therefore a second model run at hourly granularity was completed and compared to the intra-hour model run used in our NPE calculation. The value delta between the intra-hour and hourly run defines the incremental value of intra-hour modeling for customers. The difference between the hourly and intra-hour Model runs shows a $5.5 million system benefit to customers in 2025. This value is very similar to the $5.8 million E3 annual estimated benefit included in our last filing where intra-hour modeling was not performed. The support for, and calculations of, this delta value may be found in workpaper EIM hourly vs intra-hourly comparison.

Q. You mention a system benefit of $5.5 million, which is very similar to E3's $5.8 million estimate. What if the actual benefit is more significant?

A. That is a benefit, in my view, to the proposed move to a 95/5 ERM structure. If the Company is wrong in terms of its estimates, and benefits are even higher, under the proposed construct 95% of the benefits would flow through to customers. In a way it makes the argument about what the right level of benefits are moot.

Q. Has the Company included the potential impact of the Cap-and-Invest Program within the Washington Climate Commitment Act (CCA) in its modeling (RCW 70A.65)?

A. No, as many uncertainties remain on how the CCA will impact customer costs. We did include a carbon adder on Boulder Park, our only in-Washington thermal plant, thereby increasing its threshold for dispatch against market prices. But costs beyond this small impact are not yet known and will drive customer costs higher than would otherwise be the case in this filing. This uncertainty is one factor driving the Company's request for a 95/5 sharing mechanism for all NPEs currently tracked in the ERM.

Q. NPE rises significantly in 2026. What is the major driver of this rise, and

are any offsets to it included in the case?

A. The roughly $89 million increase in 2026 relative to 2025 reflects the mandated removal of Colstrip from our portfolio. See the table below for a calculation based on the 2025 mark-to-market estimated results and fuel costs. Offsetting this increase are approximately $35 million in lower depreciation and fixed operations and maintenance costs, as testified to by Company witness Ms. Andrews[9].

<u>Table No. 4 – 2026 Increase to NPE</u>

MTM Value of Power	120,537
Fuel Expense	(31,951)
Increase to NPS	88,586

III. OTHER KEY MODELING ASSUMPTIONS

Q. What other key modeling assumptions are being made by the Company?

A. Other modeling assumptions driving modeled NPE are forecasted loads and forced and planned maintenance outages at Avista plants.

Q. What is the Company's assumption for rate period loads?

A. Consistent with prior GRC proceedings, historical loads are weather-adjusted. For this filing, weather-normalized calendar year 2025 load is 1075.4 average megawatts, compared to actual test period loads of 1,095.3 average megawatts. The table below details data included in this proceeding. Please see Company witness Mr. Garbarino's testimony (Exh. MJG-1T) for additional information on weather normalization.

[9] As discussed by Ms. Andrews, Colstrip depreciation and fixed operations and maintenance costs are separately recovered from customers through Washington Tariff Schedule 99, and therefore the removal of these costs effective January 1, 2026, are not reflected in this case.

Table No. 5 – Historical Loads

Month	Test Year Load (MW)	Weather Adjustment (MW)	Modeled Load (MW)
Jan-25	1,216.0	16.1	1,232.1
Feb-25	1,227.2	0.7	1,227.8
Mar-25	1,101.3	-25.5	1,075.7
Apr-25	981.9	-6.9	975.0
May-25	955.8	0.1	955.9
Jun-25	1,002.2	-15.1	987.1
Jul-25	1,110.2	-27.8	1,082.4
Aug-25	1,160.4	-83.8	1,076.6
Sep-25	952.2	-5.8	946.4
Oct-25	932.1	46.1	978.2
Nov-25	1,198.2	-78.1	1,120.1
Dec-25	1,310.8	-57.1	1,253.6
Total	1,095.3	-19.9	1,075.4

Q. What are the assumed forced outage and planned maintenance rates for your fleet?

A. Consistent with the Power Supply Methodology, five years of data through 2022 are used to calculate average forced and planned outage rates at each of our plants (except Colstrip maintenance). The table below details these rates and are compared with the 2022 GRC filing.

Table No. 6 – Forced and Maintenance Outage Rates, 2024 and 2022 GRCs

	Forced Outage Rate			Maintenance Rate		
Facility	2025 Pro Forma	2023 Pro Forma	Difference	2025 Pro Forma	2023 Pro Forma	Difference
Boulder Park	5.8%	5.8%	0.0%	4.9%	5.0%	4.9%
Colstrip	12.6%	11.4%	1.3%	5.8%	6.0%	-0.2%
Coyote Springs 2	3.9%	2.8%	1.1%	16.5%	9.1%	7.4%
Kettle Falls	2.0%	2.7%	-0.7%	14.0%	13.6%	0.4%
Kettle Falls CT	2.1%	2.9%	-0.7%	2.6%	4.3%	-1.7%
Lancaster	2.0%	2.2%	-0.2%	5.4%	6.2%	-0.8%
Northeast	0.9%	0.9%	0.0%	n/a	n/a	n/a
Rathdrum	4.7%	4.7%	0.0%	5.2%	6.1%	5.2%

Q. Please discuss your outage assumptions for Colstrip Units 3 and 4.

A. Consistent with the Power Supply Methodology, given the planned maintenance cycle for Colstrip is four years, we used the recent eight-year average (through 2022) to include two, 4-year maintenance cycles.

Q. Are the Rathdrum and Northeast natural gas-fired plants modeled differently in this case than in the past?

A. No. Rathdrum and Northeast natural gas-fired plants provide most of our contingency and standby-reserve capabilities. Northeast, even if cost-effective to run relative to market prices, is limited to 100 hours per year due to regulation by the Spokane Regional Clean Air Agency. As such, Northeast is modeled to be set aside exclusively to meet operating reserve requirements, consistent with our last general rate case.

Northeast, on a stand-alone basis, is not large enough to meet our contingency requirements. As such, one Rathdrum unit is typically set aside by Avista's trading floor operations for reserves purposes, even when market conditions show it to be lower cost than buying from the market power. To reflect Rathdrum operations, the Model sets aside one (of two) Rathdrum units for contingency reserves during April through July when the hydro system has inadequate reserve capacity to supplement Northeast.

Q. What are the contingency and standby reserve requirements Avista must retain that removes these resources from dispatching when market prices would otherwise allow?

A. Avista's participation in the Northwest Power Pool Reserves Sharing Agreement requires us to carry three percent each of online generation and load as <u>contingency reserves</u>. Our modeled average pro forma generation of over 1,369 megawatts

(MW) and average pro forma load of 1,075 MW necessitate approximately 75 MW of average contingency reserves.

The amount of what Avista terms "standby reserves" is a bit more discretionary than contingency reserves, as standby reserves are not defined by agreement or specific regulations. Instead, we follow standard industry practice dictating utilities stand prepared with both surplus fuel and generating capacity for the inevitable loss of their largest single on-line generator. For Avista, depending on system conditions, our largest operating generator could be a smaller hydro unit at our Clark Fork Project (75-150 MW), or it could be one of our large natural gas plants like CS2 generating up to 300 MW or more.

Taken together, the contingency and standby reserves statistics described above, as they relate to pro forma dispatch, range between 132 and 408.3 MW, with an average of 319.5 MW, and require the reservation of fuel to generate electricity. The combination of Northeast and a single unit at Rathdrum approximate the minimum of this range. We generally supplement the quantities above with hydro unit capability, to have appropriate reserves in our power supply modeling. Support for this section can be found in confidential workpaper Contingency and Single-Unit Largest Unit Summary.

Q. Please describe any changes to power contracts since the 2022 General Rate Case filing and their impacts on power costs.

A. Avista updates all contracts over the pro forma term to account for expiring and new contracts. Any contract without a known and/or fixed schedule is represented with a five-year historical average (e.g., PURPA contracts).[10] The table below lists contract annual delivery levels in this case and compares them to the 2022 GRC.

[10] When five years of history are not available a lesser number of years may be used. For new resources, such as Clearwater Wind, the vendor's forecast is used until such time an adequate history exists.

<u>Table No. 7 – Wholesale Contracts (aMW)</u>

Contract	2025 Pro Forma	2023 Pro Forma
Chelan PUD	106.9	53.5
Douglas PUD	6.4	13.5
Grant PUD	37.0	38.5
Douglas Exchange Purch	-	44.2
Canadian Entitlement	(8.2)	(7.5)
CBH	44.4	-
Nichols Pumping	(5.2)	(5.2)
Palouse Wind	38.0	38.0
Rattlesnake Wind	39.4	53.5
Clearwater Wind	43.0	-
Elf I Solar	-	-
Adams Neilson Solar	-	-
Small Power	3.0	3.3
Spokane Waste-to-Energy	13.6	13.8
Stimson Lumber	3.5	4.0
Upriver	5.2	5.4
Douglas Exchange Sale	-	(47.0)
Total Contracts	327.0	208.0

Q. Are there any <u>large</u> components worth highlighting?

A. Yes, several material changes have occurred since our last case. On January 1, 2024, the Company receives an additional five percent slice of Chelan PUD's hydro fleet. Another 5 percent increase begins on January 1, 2026. The Columbia Basin Hydro (CBH) contract includes seven projects with varying online dates some of which occur beyond this filing but are included here for information. [11]

- March 1, 2023, for the Russell D. Smith (P.E.C. 22.7) Development – 6.1 MW
- May 1, 2023, for the E.B.C. 4.6 Development – 2.2 MW
- January 1, 2025, for the Summer Falls Development – 94 MW
- March 1, 2025, for the P.E.C. 66.0 Development – 2.4 MW
- October 1, 2025, for the Quincy Chute Development – 9.4 MW
- January 1, 2027, for the Main Canal Development – 26 MW
- September 1, 2030, for the P.E.C. Headworks Development – 6.2 MW

[11] CBH was evaluated and selected from Avista's 2022 Request for Proposals (RFP) process.

Avista's contract with NextEra for Clearwater Wind is expected to begin delivery in September 2024, meaning it will provide generation in both years of this multi-year rate case.[12] The Douglas purchase and sale exchange expires December 31, 2023. And, finally, Avista's contractual shares of Grant and Douglas PUD hydro project output continue to shrink over time and are modeled accordingly.

Q. Are there other contracts not included in the Model?

A. No. As with past filings, we do not model financial or index-priced contracts in the Model. Financial contracts are accounted for outside the model. Index-priced contracts have no net impact on power supply costs.

Q. How is the Adams-Neilson Solar project treated in this filing?

A. Adams-Neilson Solar, sometimes referred to as Lind Solar, exclusively serves the Solar Select program whereby self-electing customers use its energy to serve their loads. In the Model it is offset with a sale at the same contract price, removing any impact on NPE. The Company believes it is appropriate to maintain the contract in our modeling costs for ease of calculation when the current Solar Select program ends. Costs for this resource and the Solar Select program are accounted for separately in the annual ERM filing. Once prudency has been determined, it is transferred to the ERM balance for future return to customers.

Q. How are thermal fuel expenses for non-gas resources determined in the pro forma?

A. Non-gas fuel is procured for Colstrip and Kettle Falls Generating Station. Avista's coal supply agreement price is dependent on the amount of coal purchased each year. The Model estimates the amount of coal dispatch in the pro forma period based on an

[12] Modeling includes 2.8% of transmission losses per Northwestern's schedule.

estimated price from Avista's position report. After the Model dispatches the plant, our coal supply contract prices are applied to that dispatch. Wood fuel for Kettle Falls is modeled based on our contracts with fuel suppliers and inventory. The total fuel cost is determined similarly for Colstrip; expected Model dispatch is priced using budgeted prices for our fuel supply contracts. Fuel cost calculations can be found in my workpapers.

IV. MODELING RESULTS

Q. Please summarize the results from power supply modeling.

A. The Model tracks our portfolio during each hour of the pro forma study. Many of the modeling results are shared earlier in my testimony. Overall fuel costs and generation for each resource are calculated and summarized in Confidential Exh. CGK-2C and Exh. CGK-3. Market sales and purchases, and their revenues and costs, are determined as well and shown in the table below (as shown in Exh. CGK-5).

Table No. 8 – System Balancing Sales & Purchases

	2025 Pro Forma	**2023 Pro Forma**
	aMW	**aMW**
Market Purchases	4.0	8.9
Market Sales	(437.9)	(342.5)
Net	(433.9)	(333.6)
	$/MWh	**$/MWh**
Market Purchases	62.80	42.04
Market Sales	(71.38)	(41.51)
Net	(70.16)	(39.39)
	($000)	**($000)**
Market Purchases	2,213	3,281
Market Sales	(273,842)	(124,551)
Net	(271,629)	(121,270)

Market transactions, when combined with other resource and contract revenues and expenses not accounted for directly in the Model (e.g., fixed costs), determine the total NPE.

V. OVERVIEW OF PRO FORMA POWER SUPPLY ADJUSTMENT

Q. Please provide an overview of the pro forma power supply adjustment.

A. The pro forma power supply adjustment reflects revenues and expenses from the Model-defined dispatch of Avista resources, combined with wholesale market transactions under weather-normalized load and median hydro conditions. In addition, adjustments are made to reflect contract changes between the historical test year and the pro forma period and for estimated gas transportation optimization.

Q. What is the basis for the adjustments to the test period power supply revenues and expenses?

A. As explained earlier in my testimony, the test period is adjusted to normalize NPE for normal weather and median hydroelectricity generation. It also reflects the same forward electricity and natural gas prices used in the Model. It includes other known and measurable changes expected during the pro forma period. A brief description of each adjustment in Exh. CGK-3 is provided in Exh. CGK-4. Detailed workpapers support the exhibits. Each line in Exh. CGK-3 shows actual revenue or expense in the test period, the pro forma revenue or expense, and the delta between the two.

Q. What actual forward-term transactions are included in the pro forma?

A. Typically, the pro forma includes actual term transactions affecting the pro forma period. The Model is used to value all physical and financial electricity transactions in the pro forma period but is not able to model the natural gas side of our business. For natural gas, a set of mark-to-model calculations are performed outside the Model, transferred to Exh. CGK-3 and supported in workpapers.

Q. Please summarize the Company's Pro Forma Power Supply Adjustment.

A. The table below shows total NPE during the test period and the first pro forma year period.[13] For information purposes, the NPE currently in base rates is shown too.[14]

<u>Table No. 9: 2025 Pro Forma Power Supply Adjustment Summary</u>

Measure	System[(1)]	Washington Allocation[(2)]
	($000s)	($000s)
Current Authorized Power Supply Expense	$ 139,049	$ 89,547
Actual 12ME 6/30/23 Test Period Expense	$ 235,386	$ 151,589
Proposed 2025 Pro Forma Power Supply Expense	$ 175,124	$ 112,780
Proposed 2025 Expense vs Actual Test Period Expense	$ (60,262)	$ (38,809)
Proposed 2025 Expense vs Current Authorized Expense	$ 36,075	$ 23,233

(1) Excludes Transmission - see Company Witness Dillon and adjustment 3.00T. Includes load and settlement adjustment.

(2) Allocated based on ROO Current Production/Transmission Ratio of 64.40%.

The net effect of my adjustments <u>versus the test year NPE</u> is a *decrease* of $60.2 million on a system basis, or $38.8 million for Washington. However, as compared with current rates effective December 21, 2022, the incremental effect of my adjustments **<u>versus current authorized NPE</u>** is an *increase of* $36.0 million on a system basis, or **<u>$23.2 million for Washington</u>**.

Q. Please identify the specific power supply cost items not included in the Model but affecting the total adjustment being proposed.

[13] The second pro forma year, 2026, reflects the additional costs described earlier in testimony of Colstrip being removed from rates.

[14] For the remainder of my testimony, for purposes of the power supply adjustment, I will refer to the net of power supply revenues and expenses as NPE for ease of reference.

A. Besides costs determined by the Model, Exh. CGK-3 identifies non-modeled NPE items. These are expenses and revenues common to our historical filings and relate to fuel, transmission, and other miscellaneous items associated with our power supply business. In addition to these, I have added a single line item in the exhibit entitled “Forecast to Actual Market Adjustment” to reflect the $65.8 million portfolio forecast error detailed in Mr. Kinney’s direct testimony.

Q. Mr. Kinney concludes that “power supply costs cannot be forecasted accurately, and for reasons outside of utility control”.[15] Do you have any thoughts on this conclusion?

A. I do, having observed firsthand how much our pro forma NPE forecasts diverge from actual conditions. Firsthand means having performed and/or directed Company power supply modeling work since 2000 and being a Company witness on all general rate case proceedings inclusive of power supply modeling and normalized pro forma NPEs in the States of Idaho and Washington. I have analyzed and reflected on the outcomes to learn from them and to improve the forecasts given how important they are to our customers and the Company. My team has strived to forecast NPEs reflecting what the Company experiences in the pro forma period when it occurs. Yet if anything, after more than two decades of active participation in these processes, it seems the ability to forecast NPEs accurately grows more difficult each year because of factors discussed below. The landscape has changed dramatically and the factors well beyond our control.

Q. Has the Company worked diligently to manage its power supply costs?

A. Yes. I have participated in over 20 years of cross-functional meetings within

[15] Exh SJK-1T, p. 54, ll 7-8.

the Company, comprised of everyone who might be able to affect our operations and provide input to the forecasts to make them more accurate. Folks who work diligently to maximize the value of our resources and reduce NPEs no matter the market conditions faced. Much of the value achieved is through prudent resource operations within the broader wholesale markets by our trading teams. They are the best in the utility business.

Q. Have other efforts also failed to "solve" the forecasting error challenge?

A. Yes. In the 2017 to 2019 period, I led Commission-ordered power supply modeling workshops where the parties came to an agreed-methodology for modeling NPEs that greatly reduces conflict in our filings. One theme throughout that process was the importance of getting the estimate of base NPE correct. The workshop participants understood the importance of forecast accuracy, and so a good share of the work performed during the workshops was done with the goal of reducing forecast error. Ultimately, we were unable to find means to reduce expected forecast error, and instead successfully focused on lessening disagreement around certain key assumptions going into the Model.

Q. Does Avista's portfolio have a different sensitivity to market conditions relative to peer utilities, and if so, why?

A. Yes, Avista is different from other utilities regulated by this Commission. I think if you asked the other utilities, they would say the same thing. Each is unique in their own way. However, Avista has two large differences exposing us to greater NPE volatility, making the forecasting very difficult. First, our resource portfolio is nearly half hydro, meaning the costs of serving retail load are greatly reduced by zero-cost energy. This, of course, benefits customers, but comes at the expense of greater risk. Hydro output changes significantly year-to-year, season-to-season, and week-to-week. The impacts of this variation are magnified by the high correlation hydro has across the Northwest. When one hydro owner is short, all hydro owners are short, resulting in much higher costs to serve load. When one hydro owner is long, all owners are long, resulting in much lower prices and wholesale sales revenues. In other words, the risks of hydro ownership to Avista are magnified by regional dynamics.

A simple example is shown below where hydro generation falls by 20% and is replaced by increased generation from natural gas generation. The per-MWh cost of the natural gas fleet is assumed to rise modestly due to the additional generation coming from less efficient gas facilities in the resource stack that normally would not run under "pro forma" conditions. The 20% reduction in zero-cost hydro increases total portfolio costs by 32% in this example, a huge impact. Fortunately, Avista is not 100% hydro, but at half of our portfolio this type of outcome is not unreasonable to illustrate our circumstance.

<u>Table No. 10 –Illustration of Reduced Hydro on Portfolio Costs</u>

	Proforma			Actual			Delta
Source	**MWh**	**$/MWh**	**Cost**	**MWh**	**$/MWh**	**Cost**	**Cost**
Hydro	100	$ -	0	80	$ -	0	0
Gas	100	$ 50.00	5,000	120	$ 55.00	6,600	1,600
Total	**200**	**$ 25.00**	**5,000**	**200**	**$ 33.00**	**6,600**	**1,600**
							32%

Q. What is the second difference?

A. Relative to peers, Avista is positioned with more capacity than it needs to serve average loads, and this surplus offers the potential to reduce NPE greatly, by as much as 30% or 40% from what it would be if our portfolio was not in a surplus position. From January 1, 2010, through October 31, 2023, our portfolio approximated the results shown in Table No. 11 below.

Table No. 11 – Portfolio Generation Summary 2010-2023 (aMW)

Load	Non-Thermal	Thermal	Surplus
1,077	645	674	241

Table No. 11 shows our average position being surplus by 241 average megawatts (aMW), or 36% of our thermal generation levels over the 2010-2023 period. This position is liquidated in the wholesale marketplace to reduce customer rates by about $65 million as shown in Illustration No. 2 below. Though not a perfect measure given that load and resource operations vary day-to-day and even hour-to-hour, the average output from our thermal fleet is much larger than our surplus generation levels, meaning it is fair to represent most surplus sales as being sourced from the thermal fleet. For Illustration No. 2 below, I modified Illustration No. 8 from Mr. Kinney's direct testimony to illustrate the impacts of surplus thermal sale revenues on our filed NPE. For purposes of this illustration, market sale value from the thermal fleet is equal to the 36% share of overall thermal fleet MTM value. I use "MTM" as an acronym for mark-to-market, a measure of the profitability of our thermal plants after accounting for fuel and variable operating costs.

Illustration No. 2: Avista Forward Year Thermal Fleet Value and Estimated Impact on NPE 2011 through 2026

		WA Share Thermal MTM		Authorized NPE	
Year	Trade Day	Total	Mkt Sales	Total	w/o Sales
2011	9/24/10	37	9	121	130
2012	9/26/11	30	7	129	136
2013	9/26/12	33	8	118	126
2014	9/26/13	38	9	118	127
2015	9/26/14	37	8	114	122
2016	9/25/15	18	4	90	94
2017	9/26/16	21	5	89	93
2018	9/26/17	17	4	98	102
2019	9/26/18	36	8	102	111
2020	9/26/19	55	13	102	115
2021	9/25/20	56	13	96	109
2022	9/24/21	162	37	72	110
2023	9/26/22	271	63	108	170
2024	9/26/23	306	71	108	179
2025	9/26/23	282	65	90	156
2026	9/26/23	285	66	148	214
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6

* Mkt Sales MTM based on 2010-2023 ratio of surplus sales to total thermal generation

** Authorized NPE Total for 2025 uses Exhibit CGK-6, Total Power Supply Base - Washington

*** Authorized NPE Total for 2026 equals 2025 NPE escalated by MTM loss of Colstrip

This illustrates how surplus revenue increases over time with the overall value of the thermal fleet for customers. It has become a larger share of NPE, now exceeding 50%. This impact cannot be overstated. Our fleet of thermal plants used to offer about $20-$40 million a year in MTM benefit to Washington customers. Today that benefit has grown by a factor of about ten, to roughly $300 million a year, with a large share of that value coming in the form of surplus sales revenue from the wholesale market. Growing reliance on thermal operation margins very sensitive to both the absolute and relative prices of natural gas and electricity greatly increases Company (and customer) exposure to NPE forecast error driven by market and hydro conditions outside utility control.

Q. How does the value of thermal fleet market sales compare to the size of ERM deadbands?

A. Historical wholesale sales values for Washington, as shown in column four of Illustration No. 2, used to fall entirely within the $11 million range of the two deadbands, where the Company absorbs a very large share of NPE variance from authorized. This is no longer the case, as Washington's share of surplus sales is many multiples of the deadband. The illustration shows that, in the 2-year pro forma period (2025/2026), the value of thermal surplus sales is <u>six times</u> the $11 million range of the two deadbands. In the past, market changes would have modest impacts on NPE, but today the potential for variation is large, as illustrated here and in Mr. Kinney's testimony. When market conditions outside Company control impact surplus sales so greatly, to the point of being multiples of the deadbands, the purported incentive of the deadbands disappears; market conditions rather than prudent Company actions drive outcomes. No amount of prudent planning or operations can overcome this kind of market volatility.

Q. How did you arrive at thermal MTM values for the illustration above?

A. The MTM value from Mr. Kinney's testimony is included in column 3. Column 4 makes a simplified, but illustrative, calculation allocating 36% of the total MTM value of the thermal fleet as a credit against NPE. This 36% equals the ratio of estimated 2010 through October 2023 historical surplus utility sales as a share of 2010 through October 2023 historical native load.

Q. Besides your large hydro fleet and surplus market position, are there other aspects you wish to highlight making NPE more difficult to approximate today than in the past?

A. Yes. Mr. Kinney in his direct testimony describes the new drivers, but I'd like to highlight two concepts. The first is two impacts of our industry losing a significant share of traditional baseload and peaking generation resources that historically offered reliable baseload and peaking capacity. This lost capacity is often replaced with carbon-free assets offering fewer MWhs of energy relative to their nameplate ratings and very small contributions to system peak. The losses occur not just at critical peaking times where the system approaches insufficiency, but across many other peaks occurring weekly and even daily where higher cost natural gas plants must step in to meet load. Instead of a $15/MWh coal generator serving load across a peak, a $150/MWh gas peaking plant is dispatched. This circumstance is substantially what drives market prices, and our thermal fleet values, higher.

Besides the direct impacts of higher market-clearing prices, I believe the capacity shortage caused by a shift to clean energy results in market premiums as generation owners operate more conservatively to ensure they can service loads in real-time, avoid sky-rocketing margin calls, and receive the best value for their operations. If you are a wind facility owner, it is much less certain a day, week, or month ahead what your generation level will be. You therefore won't sell forward to help balance the market. If you are a natural gas plant operator, you might be forced to hold back forward sales because associated margin calls are unaffordable. Inefficiencies like this lead to higher and more volatile costs. While some of these impacts benefit the Company and its customers through higher expected values for the thermal fleet, the tradeoff is much less certainty in forecasting what NPE will be.

Q. What is the second factor increasing NPE forecast error you want to highlight?

A. The Washington Climate Commitment Act (CCA) has inserted significant uncertainty into our business that can only serve to increase NPE forecast error. All regulations and procedures developed to enforce CCA are new and largely untested, including the free allowance grant true-up process for electric load-serving entities and use by the Department of Ecology of the Allowance Price Containment Reserve to manage carbon allowance prices. Market impacts unknown today will express themselves in the forms of greater market volatility and premiums having the potential to largely affect the values and costs of our generation portfolio. These impacts will certainly add to NPE forecast error.

VI. ERM AUTHORIZED VALUES

Q. What is Avista's proposed authorized NPE and revenue for the ERM?

A. As shown in Table No. 9, the proposed authorized level of annual system NPE is $112.8 million (Washington-basis) for the Rate Year 1 (2025) pro forma period, excluding transmission revenues (sponsored by Company witness Mr. Dillon). This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale). Exh. CGK-6 provides the proposed authorized level of annual system NPE detail, including transmission expense, transmission revenue and various other expenses and revenue, totaling $89.4 million (Washington-basis).

For Rate Year 2, with the removal of Colstrip beginning in 2026, the proposed authorized level of annual system NPE detail, including transmission expense, transmission revenue and various other expenses and revenue, totals $146.4 million (Washington-basis).

Q. What is the proposed Retail Revenue Adjustment for the ERM?

A. The proposed authorized level of retail sales to be used in the ERM is the 12-months ended June 30, 2023 weather-adjusted Washington retail sales. For Rate Year 1, the proposed Retail Revenue Adjustment rate is $15.50 per MWh for the pro forma period (2025), the FERC Account average cost in the power supply pro forma. This value may be found in Exh. CGK-6. For Rate Year 2 (2026), with the removal of Colstrip beginning in 2026, the Retail Revenue Adjustment rate increases to $25.40 per MWh. Support for this value can be found in Exh. CGK-6 RY2.

Q. Finally, would you please provide an update on how the Company has complied with the 2022 Washington general rate case settlement term related to software licensing agreements and energy resources modeling.

A. Yes. As a part of the Settlement Stipulation in approved by the Commission in Dockets UE-220053 et. al., at ¶28(d), Avista agreed "to provide templates and vendor contact information for any vendor software licensing agreements (i.e., Energy Exemplar, etc.) between staff and vendors with each filing." Avista is not proposing a change for modeling software and continues to use Aurora. In communications with the vendor they do not offer a generic license that can be provided but indicated a simple letter agreement can be put together when it is requested by the Commission.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.