BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-17________

DOCKET NO. UG-17________

EXH. EMA-2

ELIZABETH M. ANDREWS

REPRESENTING AVISTA CORPORATION

**AVISTA UTILITIES**
**CALCULATION OF TRADITIONAL PRO FORMA STUDY REVENUE REQUIREMENT**
**WASHINGTON ELECTRIC**
**TWELVE MONTHS ENDED DECEMBER 31, 2016**

**The following information provides the Traditional Pro Forma Study results as required by the WUTC. This Study alone, does not provide the necessary rate relief needed to allow the Company the opportunity to earn the proposed Rate of Return (ROR) requested in this case. The base rate change noted below of $37,501,000 (including increases in power supply costs), does not reflect the requested rate relief proposed by the Company. See Exh. EMA-3 for the EOP Rate Base Study representing the Company's requested rate relief proposed in this case.**

| | | Per Traditional Pro Forma Study | | |
|---|---|---|---|---|
| | | **Base Rate Change 5/1/2018** | **Schedule 93 Expiration** | **Billed Impact 5/1/2018** |
| **Line No.** | **Description** | **(000's of Dollars)** | **(000's of Dollars)** | **(000's of Dollars)** |
| 1 | Pro Forma Rate Base | $ 1,472,291 | | |
| 2 | Proposed Rate of Return | 7.69% | | |
| 3 | Net Operating Income Requirement | $113,219 | ($9,276) | $103,943 |
| 4 | Pro Forma Net Operating Income | 89,991 | | 89,991 |
| 5 | Net Operating Income Deficiency | $23,229 | ($9,276) | $13,953 |
| 6 | Conversion Factor | 0.619413 | 0.619413 | 0.619413 |
| 7 | Revenue Requirement | **$37,501** | ($14,976) | **$22,525** |
| 8 | Total General Business Revenues | $492,134 | | |
| 9 | Percentage Revenue Increase | **7.62%** | | |
| 10 | Total Billed General Business Revenues | $511,823 | ($14,976) | |
| 11 | Percentage Revenue Increase | **7.33%** | **-2.9%** | **4.40%** |

**AVISTA UTILITIES**
**TRADITIONAL PRO FORMA COST OF CAPITAL**
**WASHINGTON ELECTRIC**

**Capital Structure**

| Component | Capital Structure | Cost | Weighted Cost |
|---|---|---|---|
| Total Debt | 51.5% | 5.62% | 2.89% |
| Common | 48.5% | 9.90% | 4.80% |
| Total | 100.00% | | 7.69% |

**AVISTA UTILITIES**
**REVENUE CONVERSION FACTOR**
**WASHINGTON ELECTRIC**
**TWELVE MONTHS ENDED DECEMBER 31, 2016**

| Line No. | Description | *Factor* |
|---|---|---|
| 1 | **Revenues** | *1.000000* |
| | **Expense:** | |
| 2 | Uncollectibles | *0.006578* |
| 3 | Commission Fees | *0.002000* |
| 4 | Washington Excise Tax | *0.038479* |
| 6 | Total Expense | *0.047057* |
| 7 | Net Operating Income Before FIT | *0.952943* |
| 8 | Federal Income Tax @ 35% | *0.333530* |
| 9 | **REVENUE CONVERSION FACTOR** | *0.619413* |

AVISTA UTILITIES
WASHINGTON ELECTRIC RESULTS - PRO FORMA
TRADITIONAL PRO FORMA STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2016
(000'S OF DOLLARS)

| | | ACTUAL RESULTS | RESTATEMENT ADJUSTMENTS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Line No. | DESCRIPTION | Results of Operations | Deferred FIT Rate Base | Deferred Debits and Credits | Working Capital | Eliminate B & O Taxes | Restate Property Tax | Uncollect. Expense | Regulatory Expense |
| | Adjustment Number | 1.00 | 1.01 | 1.02 | 1.03 | 2.01 | 2.02 | 2.03 | 2.04 |
| | Workpaper Reference | E-ROO | E-DFIT | E-DDC | E-WC | E-EBO | E-RPT | E-UE | E-RE |
| | REVENUES | | | | | | | | |
| 1 | Total General Business | $516,333 | $0 | $0 | $0 | ($17,807) | $0 | $0 | $0 |
| 2 | Interdepartmental Sales | 946 | - | - | - | - | - | - | - |
| 3 | Sales for Resale | 78,098 | - | - | - | - | - | - | - |
| 4 | Total Sales of Electricity | 595,377 | - | - | - | (17,807) | - | - | - |
| 5 | Other Revenue | 81,735 | - | - | - | (14) | - | - | - |
| 6 | Total Electric Revenue | 677,112 | - | - | - | (17,821) | - | - | - |
| | EXPENSES | | | | | | | | |
| | Production and Transmission | | | | | | | | |
| 7 | Operating Expenses | 184,672 | - | 4 | - | - | - | - | - |
| 8 | Purchased Power | 96,772 | - | | - | - | - | - | - |
| 9 | Depreciation/Amortization | 26,677 | - | - | - | - | - | - | 0 |
| 10 | Regulatory Amortization | 4,310 | - | - | - | - | - | - | - |
| 11 | Taxes | 14,904 | - | - | - | - | 86 | - | - |
| 12 | Total Production & Transmission | 327,335 | - | 4 | - | - | 86 | - | - |
| | Distribution | | | | | | | | |
| 13 | Operating Expenses | 21,420 | - | - | - | - | - | - | - |
| 14 | Depreciation/Amortization | 27,913 | - | - | - | - | - | - | - |
| 15 | Regulatory Amortization | 0 | - | - | - | - | - | - | - |
| 16 | Taxes | 45,258 | - | - | - | (17,674) | (336) | - | - |
| 17 | Total Distribution | 94,591 | - | - | - | (17,674) | (336) | - | - |
| 18 | Customer Accounting | 11,733 | - | 8 | - | - | - | 1,321 | - |
| 19 | Customer Service & Information | 18,081 | - | - | - | - | - | - | - |
| 20 | Sales Expenses | 0 | - | - | - | - | - | - | - |
| | Administrative & General | | | | | | | | |
| 21 | Operating Expenses | 50,568 | - | - | - | - | - | - | 7 |
| 22 | Depreciation/Amortization | 23,877 | - | - | - | - | - | - | - |
| 23 | Taxes | 0 | - | - | - | - | - | - | - |
| 24 | Total Admin. & General | 74,445 | - | - | - | - | - | - | 7 |
| 25 | Total Electric Expenses | 526,185 | - | 12 | - | (17,674) | (250) | 1,321 | 7 |
| 26 | OPERATING INCOME BEFORE FIT | 150,927 | - | (12) | - | (147) | 250 | (1,321) | (7) |
| | FEDERAL INCOME TAX | | | | | | | | |
| 27 | Current Accrual | (25,741) | - | (4) | - | (51) | 88 | (462) | (2) |
| 28 | Debt Interest | 0 | (8) | - | 30 | - | - | - | - |
| 29 | Deferred Income Taxes | 66,436 | - | - | - | - | - | - | - |
| 30 | Amortized ITC - Noxon | (325) | - | - | - | - | - | - | - |
| 31 | NET OPERATING INCOME | $110,557 | $8 | ($8) | ($30) | ($96) | $163 | ($859) | ($5) |
| | RATE BASE | | | | | | | | |
| | PLANT IN SERVICE | | | | | | | | |
| 32 | Intangible | $156,057 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 33 | Production | 832,833 | - | - | - | - | - | - | - |
| 34 | Transmission | 430,613 | - | - | - | - | - | - | - |
| 35 | Distribution | 970,455 | - | - | - | - | - | - | - |
| 36 | General | 233,266 | - | - | - | - | - | - | - |
| 37 | Total Plant in Service | 2,623,224 | - | - | - | - | - | - | - |
| | ACCUMULATED DEPRECIATION/AMORT | | | | | | | | |
| 38 | Intangible | (30,914) | - | - | - | - | - | - | - |
| 39 | Production | (351,625) | - | - | - | - | - | - | - |
| 40 | Transmission | (135,624) | - | - | - | - | - | - | - |
| 41 | Distribution | (295,383) | - | - | - | - | - | - | - |
| 42 | General | (80,093) | - | - | - | - | - | - | - |
| 43 | Total Accumulated Depreciation | (893,639) | - | - | - | - | - | - | - |
| 44 | NET PLANT | 1,729,585 | - | - | - | - | - | - | - |
| 45 | DEFERRED TAXES | (354,707) | 806 | - | - | - | - | - | - |
| 46 | Net Plant After DFIT | 1,374,878 | 806 | - | - | - | - | - | - |
| 47 | DEFERRED DEBITS AND CREDITS & OTHER | 4,568 | - | - | - | - | - | - | - |
| 48 | WORKING CAPITAL | 65,480 | - | - | (3,006) | - | - | - | - |
| 49 | TOTAL RATE BASE | 1,444,926 | $806 | $0 | ($3,006) | $0 | $0 | $0 | $0 |
| 50 | RATE OF RETURN | 7.65% | | | | | | | |
| 51 | REVENUE REQUIREMENT | 901 | 87 | 13 | (324) | 154 | (262) | 1,386 | 7 |

AVISTA UTILITIES
WASHINGTON ELECTRIC RESULTS - PRO FORMA
TRADITIONAL PRO FORMA STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2016
(000'S OF DOLLARS)

| Line No. | DESCRIPTION | Injuries and Damages | FIT/DFIT/ ITC Expense | Office Space Charges to Non-Utility | Restate Excise Taxes | Net Gains / Losses | Weather Normalization | Eliminate Adder Schedules | Misc. Restating Non-Util / Non-Recurring Expenses |
|---|---|---|---|---|---|---|---|---|---|
| | Adjustment Number | **2.05** | **2.06** | **2.07** | **2.08** | **2.09** | **2.10** | **2.11** | **2.12** |
| | Workpaper Reference | **E-ID** | **E-FIT** | **E-OSC** | **E-RET** | **E-NGL** | **E-WN** | **E-EAS** | **E-MR** |
| | REVENUES | | | | | | | | |
| 1 | Total General Business | $0 | $0 | $0 | $0 | $0 | $7,392 | ($18,203) | $0 |
| 2 | Interdepartmental Sales | - | - | - | - | - | - | - | - |
| 3 | Sales for Resale | - | - | - | - | - | - | - | - |
| 4 | Total Sales of Electricity | - | - | - | - | - | 7,392 | (18,203) | - |
| 5 | Other Revenue | - | - | - | - | - | (5,775) | 684 | (2,566) |
| 6 | Total Electric Revenue | - | - | - | - | - | 1,617 | (17,519) | (2,566) |
| | EXPENSES | | | | | | | | |
| | Production and Transmission | | | | | | | | |
| 7 | Operating Expenses | - | - | - | - | - | - | (383) | (5) |
| 8 | Purchased Power | - | - | - | - | - | - | - | - |
| 9 | Depreciation/Amortization | - | - | - | - | - | - | - | - |
| 10 | Regulatory Amortization | - | - | - | - | - | - | 395 | - |
| 11 | Taxes | - | - | - | - | - | - | - | - |
| 12 | Total Production & Transmission | - | - | - | - | - | - | 12 | (5) |
| | Distribution | | | | | | | | |
| 13 | Operating Expenses | - | - | - | - | - | - | - | (2) |
| 14 | Depreciation/Amortization | - | - | - | - | (94) | - | - | - |
| 15 | Regulatory Amortization | - | - | - | - | - | - | - | - |
| 16 | Taxes | - | - | - | (62) | - | 284 | (700) | - |
| 17 | Total Distribution | - | - | - | (62) | (94) | 284 | (700) | (2) |
| 18 | Customer Accounting | - | - | - | - | - | 49 | (120) | - |
| 19 | Customer Service & Information | - | - | - | - | - | - | (16,675) | - |
| 20 | Sales Expenses | - | - | - | - | - | - | - | - |
| | Administrative & General | | | | | | | | |
| 21 | Operating Expenses | 151 | - | (31) | - | - | 15 | (36) | (1,068) |
| 22 | Depreciation/Amortization | - | - | - | - | - | - | - | - |
| 23 | Taxes | - | - | - | - | - | - | - | - |
| 24 | Total Admin. & General | 151 | - | (31) | - | - | 15 | (36) | (1,068) |
| 25 | Total Electric Expenses | 151 | - | (31) | (62) | (94) | 348 | (17,519) | (1,075) |
| 26 | OPERATING INCOME BEFORE FIT | (151) | - | 31 | 62 | 94 | 1,269 | - | (1,491) |
| | FEDERAL INCOME TAX | | | | | | | | |
| 27 | Current Accrual | (53) | 110 | 11 | 22 | 33 | 444 | - | (522) |
| 28 | Debt Interest | - | - | - | - | - | - | - | - |
| 29 | Deferred Income Taxes | - | (40) | - | - | - | - | - | - |
| 30 | Amortized ITC - Noxon | - | (1) | - | - | - | - | - | - |
| 31 | NET OPERATING INCOME | ($98) | ($69) | $20 | $40 | $61 | $825 | $0 | ($969) |
| | RATE BASE | | | | | | | | |
| | PLANT IN SERVICE | | | | | | | | |
| 32 | Intangible | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 33 | Production | - | - | - | - | - | - | - | - |
| 34 | Transmission | - | - | - | - | - | - | - | - |
| 35 | Distribution | - | - | - | - | - | - | - | - |
| 36 | General | - | - | - | - | - | - | - | - |
| 37 | Total Plant in Service | - | - | - | - | - | - | - | - |
| | ACCUMULATED DEPRECIATION/AMORT | | | | | | | | |
| 38 | Intangible | - | - | - | - | - | - | - | - |
| 39 | Production | - | - | - | - | - | - | - | - |
| 40 | Transmission | - | - | - | - | - | - | - | - |
| 41 | Distribution | - | - | - | - | - | - | - | - |
| 42 | General | - | - | - | - | - | - | - | - |
| 43 | Total Accumulated Depreciation | - | - | - | - | - | - | - | - |
| 44 | NET PLANT | - | - | - | - | - | - | - | - |
| 45 | DEFERRED TAXES | - | - | - | - | - | - | - | - |
| 46 | Net Plant After DFIT | - | - | - | - | - | - | - | - |
| 47 | DEFERRED DEBITS AND CREDITS & OTHER | - | - | - | - | - | - | - | - |
| 48 | WORKING CAPITAL | - | - | - | - | - | - | - | - |
| 49 | TOTAL RATE BASE | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 50 | RATE OF RETURN | | | | | | | | |
| 51 | REVENUE REQUIREMENT | 158 | 111 | (33) | (65) | (99) | (1,332) | - | 1,565 |

AVISTA UTILITIES
WASHINGTON ELECTRIC RESULTS - PRO FORMA
TRADITIONAL PRO FORMA STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2016
(000'S OF DOLLARS)

| Line No. | DESCRIPTION | Eliminate WA Power Cost Defer | Nez Perce Settlement Adjustment | Restating Incentives | Normalize CS2/Colstrip Major Maint | Restate Debt Interest | (Authorized P.S. @ Authorized P/T ratio) Authorized Power Supply | Restated TOTAL |
|---|---|---|---|---|---|---|---|---|
| | Adjustment Number | **2.13** | **2.14** | **2.15** | **2.16** | **2.17** | **2.18** | **R-Ttl** |
| | Workpaper Reference | **E-EWPC** | **E-NPS** | **E-RI** | **E-PMM** | **E-RDI** | **E-APS** | |
| | REVENUES | | | | | | | |
| 1 | Total General Business | $4,698 | $0 | $0 | $0 | $0 | $0 | **$492,413** |
| 2 | Interdepartmental Sales | ` | - | - | - | - | - | **946** |
| 3 | Sales for Resale | - | - | - | - | - | (20,773) | **57,325** |
| 4 | Total Sales of Electricity | 4,698 | - | - | - | - | (20,773) | **550,684** |
| 5 | Other Revenue | - | - | - | - | - | (56,948) | **17,116** |
| 6 | Total Electric Revenue | 4,698 | - | - | - | - | (77,721) | **567,800** |
| | EXPENSES | | | | | | | |
| | Production and Transmission | | | | | | | |
| 7 | Operating Expenses | (2,270) | (4) | - | (1,174) | - | (46,240) | **134,600** |
| 8 | Purchased Power | - | - | - | - | - | (19,641) | **77,131** |
| 9 | Depreciation/Amortization | - | - | - | - | - | - | **26,677** |
| 10 | Regulatory Amortization | - | - | - | - | - | | **4,705** |
| 11 | Taxes | - | - | - | - | - | - | **14,990** |
| 12 | Total Production & Transmission | (2,270) | (4) | - | (1,174) | - | (65,881) | **258,103** |
| | Distribution | | | | | | | |
| 13 | Operating Expenses | - | - | | - | - | - | **21,418** |
| 14 | Depreciation/Amortization | - | - | - | - | - | - | **27,819** |
| 15 | Regulatory Amortization | - | - | - | - | - | - | **-** |
| 16 | Taxes | 181 | - | - | - | - | - | **26,951** |
| 17 | Total Distribution | 181 | - | - | - | - | - | **76,188** |
| 18 | Customer Accounting | 30 | - | - | - | - | - | **13,021** |
| 19 | Customer Service & Information | - | - | - | - | - | - | **1,406** |
| 20 | Sales Expenses | - | - | - | - | - | - | **-** |
| | Administrative & General | | | | | | | |
| 21 | Operating Expenses | 9 | - | (626) | - | - | - | **48,989** |
| 22 | Depreciation/Amortization | - | - | - | - | - | - | **23,877** |
| 23 | Taxes | - | - | - | - | - | - | **-** |
| 24 | Total Admin. & General | 9 | - | (626) | - | - | - | **72,866** |
| 25 | Total Electric Expenses | (2,050) | (4) | (626) | (1,174) | - | (65,881) | **421,584** |
| 26 | OPERATING INCOME BEFORE FIT | 6,748 | 4 | 626 | 1,174 | - | (11,840) | **146,216** |
| | FEDERAL INCOME TAX | | | | | | | |
| 27 | Current Accrual | 1,567 | 1 | 219 | 411 | (860) | (4,144) | **(28,935)** |
| 28 | Debt Interest | - | - | - | - | | - | **22** |
| 29 | Deferred Income Taxes | 795 | - | - | - | - | - | **67,191** |
| 30 | Amortized ITC - Noxon | - | - | - | - | - | - | **(326)** |
| 31 | NET OPERATING INCOME | $4,386 | $3 | 407 | 763 | 860 | ($7,696) | **108,263** |
| | RATE BASE | | | | | | | |
| | PLANT IN SERVICE | | | | | | | |
| 32 | Intangible | $0 | $0 | $0 | $0 | $0 | $0 | **$156,057** |
| 33 | Production | - | - | - | - | - | - | **832,833** |
| 34 | Transmission | - | - | - | - | - | - | **430,613** |
| 35 | Distribution | - | - | - | - | - | - | **970,455** |
| 36 | General | - | - | - | - | - | - | **233,266** |
| 37 | Total Plant in Service | - | - | - | - | - | - | **2,623,224** |
| | ACCUMULATED DEPRECIATION/AMORT | | | | | | - | |
| 38 | Intangible | - | - | - | - | - | - | **(30,914)** |
| 39 | Production | - | - | - | - | - | - | **(351,625)** |
| 40 | Transmission | - | - | - | - | - | - | **(135,624)** |
| 41 | Distribution | - | - | - | - | - | - | **(295,383)** |
| 42 | General | - | - | - | - | - | - | **(80,093)** |
| 43 | Total Accumulated Depreciation | - | - | - | - | - | - | **(893,639)** |
| 44 | NET PLANT | - | - | - | - | - | - | **1,729,585** |
| 45 | DEFERRED TAXES | - | - | - | - | - | - | **(353,901)** |
| 46 | Net Plant After DFIT | - | - | - | - | - | - | **1,375,684** |
| 47 | DEFERRED DEBITS AND CREDITS & OTHER | - | - | - | - | - | - | **4,568** |
| 48 | WORKING CAPITAL | - | - | - | - | - | - | **62,474** |
| 49 | TOTAL RATE BASE | $0 | $0 | $0 | $0 | $0 | $0 | **$1,442,726** |
| 50 | RATE OF RETURN | | | | | | | **(1)** |
| 51 | REVENUE REQUIREMENT | (7,081) | (4) | (657) | (1,232) | (1,388) | 12,425 | 4,330 |

**(1) The Restated TOTAL column does not represent 12/31/2016 Test Period Commission Basis results of operation on a normalized basis (CBR basis). Two differences exist here: 1) inclusion of proposed (Pro Forma) cost debt (pro forma versus CBR cost of debt) impacting Adjustment 2.17 above; and 2) Authorized (ERM) Power Supply (Adj 2.18 above) versus revised Authorized Power Supply (CB) which included the updated Production/ Transmission (P/T) ratio. The P/T ratio update is included in PF Power Supply Adjustment 4.00 in order to seperate increased power supply costs from non-energy increased costs requested by the Company.**

**PRO FORMA ADJUSTMENTS**

AVISTA UTILITIES
WASHINGTON ELECTRIC RESULTS - PRO FORMA
TRADITIONAL PRO FORMA STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2016
(000'S OF DOLLARS)

| Line No. | DESCRIPTION | NON ERM Pro Forma Trans/Power Sup Non-ERM Rev/Exp | Pro Forma Labor Non-Exec | Pro Forma Labor Exec | Pro Forma Employee Benefits | Pro Forma Incentive Expenses | Pro Forma Property Tax | Pro Forma IS/IT Expense | Pro Forma Revenue Normalization |
|---|---|---|---|---|---|---|---|---|---|
| | Adjustment Number | **3.01** | **3.02** | **3.03** | **3.04** | **3.05** | **3.06** | **3.07** | **3.08** |
| | Workpaper Reference | **E-PTR** | **E-PLN** | **E-PLE** | **E-PEB** | **E-PI** | **E-PPT** | **E-CI** | **E-PREV** |
| | REVENUES | | | | | | | | |
| 1 | Total General Business | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($1,225) |
| 2 | Interdepartmental Sales | - | - | - | - | - | - | - | - |
| 3 | Sales for Resale | - | - | - | - | - | - | - | - |
| 4 | Total Sales of Electricity | - | - | - | - | - | - | - | (1,225) |
| 5 | Other Revenue | 71 | - | - | - | - | - | - | (3,887) |
| 6 | Total Electric Revenue | 71 | - | - | - | - | - | - | (5,112) |
| | EXPENSES | | | | | | | | |
| | Production and Transmission | | | | | | | | |
| 7 | Operating Expenses | 172 | 999 | - | (125) | - | - | - | - |
| 8 | Purchased Power | - | - | - | | - | - | - | - |
| 9 | Depreciation/Amortization | - | - | - | - | - | - | - | - |
| 10 | Regulatory Amortization | | | | | - | - | - | - |
| 11 | Taxes | - | - | - | - | - | 1,578 | - | - |
| 12 | Total Production & Transmission | 172 | 999 | - | (125) | - | 1,578 | - | - |
| | Distribution | | | | | | | | |
| 13 | Operating Expenses | - | 604 | | (77) | | - | - | - |
| 14 | Depreciation/Amortization | - | - | - | - | - | - | - | - |
| 15 | Regulatory Amortization | - | - | - | - | - | - | - | - |
| 16 | Taxes | - | - | - | - | - | 880 | - | (47) |
| 17 | Total Distribution | - | 604 | - | (77) | - | 880 | - | (47) |
| 18 | Customer Accounting | - | 322 | | (41) | - | - | - | (8) |
| 19 | Customer Service & Information | - | 27 | | (3) | - | - | - | - |
| 20 | Sales Expenses | - | | | | - | - | - | - |
| | Administrative & General | | | | | | | | |
| 21 | Operating Expenses | - | 912 | (33) | (114) | 119 | - | 694 | (2) |
| 22 | Depreciation/Amortization | - | - | - | - | - | - | - | - |
| 23 | Taxes | - | - | - | - | - | - | - | - |
| 24 | Total Admin. & General | - | 912 | (33) | (114) | 119 | - | 694 | (2) |
| 25 | Total Electric Expenses | 172 | 2,864 | (33) | (360) | 119 | 2,458 | 694 | (57) |
| 26 | OPERATING INCOME BEFORE FIT | (101) | (2,864) | 33 | 360 | (119) | (2,458) | (694) | (5,055) |
| | FEDERAL INCOME TAX | | | | | | | | |
| 27 | Current Accrual | (35) | (1,002) | 12 | 126 | (42) | (860) | (243) | (1,769) |
| 28 | Debt Interest | - | - | - | - | - | - | - | - |
| 29 | Deferred Income Taxes | - | - | - | - | - | - | - | - |
| 30 | Amortized ITC - Noxon | - | - | - | - | - | - | - | - |
| 31 | NET OPERATING INCOME | ($66) | ($1,862) | $21 | $234 | ($77) | ($1,598) | ($451) | (3,286) |
| | RATE BASE | | | | | | | | |
| | PLANT IN SERVICE | | | | | | | | |
| 32 | Intangible | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 33 | Production | - | - | - | - | - | - | - | - |
| 34 | Transmission | - | - | - | - | - | - | - | - |
| 35 | Distribution | - | - | - | - | - | - | - | - |
| 36 | General | - | - | - | - | - | - | - | - |
| 37 | Total Plant in Service | - | - | - | - | - | - | - | - |
| | ACCUMULATED DEPRECIATION/AMORT | - | - | - | - | | | | |
| 38 | Intangible | - | - | - | - | - | - | - | - |
| 39 | Production | - | - | - | - | - | - | - | - |
| 40 | Transmission | - | - | - | - | - | - | - | - |
| 41 | Distribution | - | - | - | - | - | - | - | - |
| 42 | General | - | - | - | - | - | - | - | - |
| 43 | Total Accumulated Depreciation | - | - | - | - | - | - | - | - |
| 44 | NET PLANT | - | - | - | - | - | - | - | - |
| 45 | DEFERRED TAXES | - | - | - | - | - | - | - | - |
| 46 | Net Plant After DFIT | - | - | - | - | - | - | - | - |
| 47 | DEFERRED DEBITS AND CREDITS & OTHER | - | - | - | - | - | - | - | - |
| 48 | WORKING CAPITAL | - | - | - | - | - | - | - | - |
| 49 | TOTAL RATE BASE | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 50 | RATE OF RETURN | | | | | | | | |
| 51 | REVENUE REQUIREMENT | 106 | 3,005 | (35) | (378) | 125 | 2,579 | 728 | 5,305 |

AVISTA UTILITIES
WASHINGTON ELECTRIC RESULTS - PRO FORMA
TRADITIONAL PRO FORMA STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2016
(000'S OF DOLLARS)

| Line No. | DESCRIPTION | Pro Forma Def. Debits, Credits & Regulatory Amorts | Pro Forma 2017 Threshhold Capital Adds | Pro Forma O&M Offsets | Pro Forma Director Fees Exp | PF Normalize CS2/Colstrip Major Maint | Pro Forma Underground Equip Inspection | Non-Energy Pro Forma Sub-Total |
|---|---|---|---|---|---|---|---|---|
| | Adjustment Number | **3.09** | **3.10** | **3.11** | **3.12** | **3.13** | **3.14** | **PF-SubTtl** |
| | Workpaper Reference | **E-PRA** | **E-PCAP16** | **E-POFF** | **E-PDF** | **E-PNM** | **E-PUEI** | |
| | REVENUES | | | | | | | |
| 1 | Total General Business | $0 | $0 | $0 | $0 | $0 | $0 | **$491,188** |
| 2 | Interdepartmental Sales | - | - | - | - | - | - | **946** |
| 3 | Sales for Resale | - | - | - | - | - | - | **57,325** |
| 4 | Total Sales of Electricity | - | - | - | - | - | - | **549,459** |
| 5 | Other Revenue | - | - | - | - | - | - | **13,300** |
| 6 | Total Electric Revenue | - | - | - | - | - | - | **562,759** |
| | EXPENSES | | | | | | | |
| | Production and Transmission | | | | | | | **-** |
| 7 | Operating Expenses | (248) | - | - | - | 347 | - | **135,745** |
| 8 | Purchased Power | - | - | - | - | - | - | **77,131** |
| 9 | Depreciation/Amortization | - | 129 | - | - | - | - | **26,806** |
| 10 | Regulatory Amortization | (1,393) | | - | - | - | - | **3,312** |
| 11 | Taxes | - | - | - | - | - | - | **16,568** |
| 12 | Total Production & Transmission | (1,641) | 129 | - | - | 347 | - | **259,562** |
| | Distribution | | | | | | | **-** |
| 13 | Operating Expenses | - | - | - | - | - | 532 | **22,477** |
| 14 | Depreciation/Amortization | - | 795 | (875) | - | - | - | **27,739** |
| 15 | Regulatory Amortization | - | - | - | - | - | - | **-** |
| 16 | Taxes | - | - | - | - | - | - | **27,784** |
| 17 | Total Distribution | - | 795 | (875) | - | - | 532 | **78,000** |
| 18 | Customer Accounting | - | - | - | - | - | - | **13,294** |
| 19 | Customer Service & Information | - | - | - | - | - | - | **1,430** |
| 20 | Sales Expenses | - | - | - | - | - | - | **-** |
| | Administrative & General | | | | | | | |
| 21 | Operating Expenses | - | - | (112) | 375 | - | - | **50,828** |
| 22 | Depreciation/Amortization | - | 2,297 | - | - | - | - | **26,174** |
| 23 | Taxes | - | - | - | - | - | - | **-** |
| 24 | Total Admin. & General | - | 2,297 | (112) | 375 | - | - | **77,002** |
| 25 | Total Electric Expenses | (1,641) | 3,221 | (987) | 375 | 347 | 532 | **429,288** |
| 26 | OPERATING INCOME BEFORE FIT | 1,641 | (3,221) | 987 | (375) | (347) | (532) | **133,471** |
| | FEDERAL INCOME TAX | | | | | | | |
| 27 | Current Accrual | 574 | (1,127) | 345 | (131) | (121) | (186) | **(33,395)** |
| 28 | Debt Interest | 54 | (353) | - | - | - | - | **(277)** |
| 29 | Deferred Income Taxes | - | - | - | - | - | - | **67,191** |
| 30 | Amortized ITC - Noxon | - | - | - | - | - | - | **(326)** |
| 31 | NET OPERATING INCOME | $1,013 | ($1,741) | 642 | (244) | (226) | (346) | **100,278** |
| | RATE BASE | | | | | | | |
| | PLANT IN SERVICE | | | | | | | |
| 32 | Intangible | $0 | $10,319 | $0 | $0 | $0 | $0 | **$166,376** |
| 33 | Production | - | 6,889 | - | - | - | - | **839,722** |
| 34 | Transmission | - | - | - | - | - | - | **430,613** |
| 35 | Distribution | - | 27,209 | - | - | - | - | **997,664** |
| 36 | General | - | - | - | - | - | - | **233,266** |
| 37 | Total Plant in Service | - | 44,417 | - | - | - | - | **2,667,641** |
| | ACCUMULATED DEPRECIATION/AMORT | | | | | | | |
| 38 | Intangible | - | (1,092) | - | - | - | - | **(32,006)** |
| 39 | Production | - | (95) | - | - | - | - | **($351,720)** |
| 40 | Transmission | - | - | - | - | - | - | **(135,624)** |
| 41 | Distribution | - | (327) | - | - | - | - | **(295,710)** |
| 42 | General | - | - | - | - | - | - | **(80,093)** |
| 43 | Total Accumulated Depreciation | - | (1,514) | - | - | - | - | **(895,153)** |
| 44 | NET PLANT | - | 42,903 | - | - | - | - | **1,772,488** |
| 45 | DEFERRED TAXES | - | (7,992) | - | - | - | - | **(361,893)** |
| 46 | Net Plant After DFIT | - | 34,911 | - | - | - | - | **1,410,595** |
| 47 | DEFERRED DEBITS AND CREDITS & OTHER | (5,346) | - | - | - | - | - | **(778)** |
| 48 | WORKING CAPITAL | - | - | - | - | - | - | **62,474** |
| 49 | TOTAL RATE BASE | (5,346) | $34,911 | $0 | $0 | $0 | $0 | **1,472,291** |
| 50 | RATE OF RETURN | | | | | | | |
| 51 | REVENUE REQUIREMENT | (2,298) | 7,144 | (1,036) | 394 | 364 | 558 | **20,892** |
| | | | | | | | | **Pro Forma Non-Energy** |
| | | | | | | | | 4.25% |

AVISTA UTILITIES
WASHINGTON ELECTRIC RESULTS - PRO FORMA
TRADITIONAL PRO FORMA STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2016
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| Line No. | DESCRIPTION | ERM ADJUSTMENT<br>ERM Related Only<br>Pro Forma Power Supply & Transm Revs | Pro Forma Including PS Total | Tariff 93 expires upon effective date of new base rates from this GRC<br>9/1/2017 Power Supply Update Tariff Schedule 93 | Incremental impact of Pro Forma Power Supply and Expiration of Schedule 93<br>Power Supply Incremental (Billed) Impact Increase / (Decrease) |
|---|---|---|---|---|---|
| | Adjustment Number | 4.00 | PF-Ttl | | |
| | Workpaper Reference | E-PPS | | | |
| | REVENUES | | | | |
| 1 | Total General Business | $0 | $491,188 | $0 | $0 |
| 2 | Interdepartmental Sales | - | 946 | - | - |
| 3 | Sales for Resale | (21,762) | 35,563 | (26,116) | 4,354 |
| 4 | Total Sales of Electricity | (21,762) | 527,697 | (26,116) | 4,354 |
| 5 | Other Revenue | (268) | 13,032 | - | (268) |
| 6 | Total Electric Revenue | (22,030) | 540,729 | (26,116) | 4,086 |
| | EXPENSES | | | | |
| | Production and Transmission | | - | | |
| 7 | Operating Expenses | (2,292) | 133,453 | (5,139) | 2,847 |
| 8 | Purchased Power | (3,911) | 73,220 | (6,706) | 2,795 |
| 9 | Depreciation/Amortization | - | 26,806 | - | - |
| 10 | Regulatory Amortization | | 3,312 | | - |
| 11 | Taxes | - | 16,568 | - | - |
| 12 | Total Production & Transmission | (6,203) | 253,359 | (11,845) | 5,642 |
| | Distribution | | | | |
| 13 | Operating Expenses | - | 22,477 | - | - |
| 14 | Depreciation/Amortization | - | 27,739 | - | - |
| 15 | Regulatory Amortization | - | - | - | - |
| 16 | Taxes | - | 27,784 | - | - |
| 17 | Total Distribution | - | 78,000 | - | - |
| 18 | Customer Accounting | - | 13,294 | - | - |
| 19 | Customer Service & Information | - | 1,430 | - | - |
| 20 | Sales Expenses | - | - | - | - |
| | Administrative & General | | | | |
| 21 | Operating Expenses | - | 50,828 | - | - |
| 22 | Depreciation/Amortization | - | 26,174 | - | - |
| 23 | Taxes | - | - | - | - |
| 24 | Total Admin. & General | - | 77,002 | - | - |
| 25 | Total Electric Expenses | (6,203) | 423,085 | (11,845) | 5,642 |
| 26 | OPERATING INCOME BEFORE FIT | (15,827) | 117,644 | (14,271) | (1,556) |
| | FEDERAL INCOME TAX | | | | |
| 27 | Current Accrual | (5,539) | (38,935) | (4,995) | (545) |
| 28 | Debt Interest | - | (277) | - | - |
| 29 | Deferred Income Taxes | - | 67,191 | - | - |
| 30 | Amortized ITC - Noxon | - | (326) | - | - |
| 31 | NET OPERATING INCOME | ($10,288) | 89,991 | ($9,276) | ($1,011) |
| | RATE BASE | | | | |
| | PLANT IN SERVICE | | | | |
| 32 | Intangible | $0 | $166,376 | $0 | $0 |
| 33 | Production | - | 839,722 | - | - |
| 34 | Transmission | - | 430,613 | - | - |
| 35 | Distribution | - | 997,664 | - | - |
| 36 | General | - | 233,266 | - | - |
| 37 | Total Plant in Service | - | 2,667,641 | - | - |
| | ACCUMULATED DEPRECIATION/AMORT | | | | |
| 38 | Intangible | - | (32,006) | - | - |
| 39 | Production | - | ($351,720) | - | - |
| 40 | Transmission | - | (135,624) | - | - |
| 41 | Distribution | - | (295,710) | - | - |
| 42 | General | - | (80,093) | - | - |
| 43 | Total Accumulated Depreciation | - | (895,153) | - | - |
| 44 | NET PLANT | - | 1,772,488 | - | - |
| 45 | DEFERRED TAXES | - | (361,893) | - | - |
| 46 | Net Plant After DFIT | - | 1,410,595 | - | - |
| 47 | DEFERRED DEBITS AND CREDITS & OTHER | - | (778) | - | - |
| 48 | WORKING CAPITAL | - | 62,474 | - | - |
| 49 | TOTAL RATE BASE | $0 | 1,472,291 | $0 | $0 |
| 50 | RATE OF RETURN | | | | |
| 51 | REVENUE REQUIREMENT | 16,609 | 37,501 | 14,976 | 1,633 |
| | | ERM Power Supply Adj | Ttl Pro Forma w/ PS | Sch. 93 PS Update | Incremental Increase / (Decrease) in PS Costs |
| | | 3.37% | 7.62% | *2.9%* | *0.32%* |

## Exh. EMA-2 – Electric Traditional Pro Forma Study

**Q. Please explain the purpose of the electric Traditional Pro Forma Study.**

A. In determining the Company's need for rate relief, the Company first completed its Traditional Pro Forma Study, adjusting 2016 historical test year balances for restating and pro forma adjustments. The restating and pro forma adjustments included in this study are those traditionally accepted and approved by the Washington Utilities and Transportation Commission (WUTC or Commission). This study alone, does not provide the necessary rate relief needed to allow the Company the opportunity to earn the proposed ROR requested in this case, and therefore, on its own, is not the basis of the Company's request. The results of the electric Traditional Pro Forma Study for Rate Year 1 is $37,501,000 million.[1/2]

**Q. Please explain what is shown on pages 1 – 3 of Exh. EMA-2.**

A. Page 1 of Exh. EMA-2 shows, at line 7, the calculation of the electric Pro Forma level revenue requirement of $37,501,000, or 7.62% revenue increase, as shown on line 9. This page also shows the effect on billed rates, <u>per the Traditional Pro Forma Study</u>, with the expiration of Schedule 93 (Power Cost Rate Adjustment (PCRA)) totaling $14.976

[1] The electric Pro Forma revenue requirement includes $16.6 million of increased power supply costs. If the proposed $15.0 million Power Supply Rate Adjustment is approved effective September 1, 2017, the total revenue requirement amount would be offset by the $15.0 million on a billed basis.

[2] After completion of the Company's revenue requirement, we learned of the impact of a new aquatic invasive species fee, to be paid to the State of Montana, related to the Company's Noxon Rapids hydroelectric generating facility. Beginning on July 1, 2017, based on recently signed legislation, Avista will be required to pay this fee to the State of Montana. This fee will be imposed on a quarterly basis until June 30, 2019, at a rate of $795.76/MW of a "hydroelectric facility's" nameplate capacity. This fee is estimated to be approximately $1.6 million per year, or $1.0 million Washington's share. The Company will update this information during the process of this case.

million[3], resulting in a bill impact of $22,525,000, or 4.40% on an overall billed basis (net of the expiration of Schedule 93).

Page 2 of Exh. EMA-2, shows the Cost of Capital and Capital Structure included in the Traditional Pro Forma Study, including: 1) 48.5% Common Equity / 51.5% Debt capital structure[4]; 2) Return on Equity of 9.9%; and 3) cost of debt of 5.62%, resulting in an overall Rate of Return (weighted average cost of capital) of 7.69%. Company witness Mr. Thies discusses the Company's rate of return and the capital structure, while Company witness Mr. McKenzie provides additional testimony related to the appropriate return on equity for Avista.

Page 3 shows the derivation of the electric net-operating-income-to-gross-revenue conversion factor. The conversion factor takes into account uncollectible accounts receivable, Commission fees and Washington State excise taxes. Federal income taxes are reflected at 35%.

**Q. Now turning to pages pages 4 through 9 of Exh. EMA-2, please explain what is included on those pages?**

A. Page 4 begins with actual operating results and rate base for the twelve-months-ending December 31, 2016 test period on an AMA basis in column (1.00). Individual normalizing and restating adjustments that are standard components of our

[3] Company witness Mr. Ehrbar discusses the PCRA as it relates to this general rate case. Schedule 93 includes the proposed update to current authorized power supply costs that are tracked through the Company's Energy Recovery Mechanism (ERM), increasing power supply net expense $14.976 million effective September 1, 2017 (or 2.9%). With this general rate case the Company is proposing to update power supply base costs per the pro forma period for Rate Year 1 (May 1, 2018-April 30, 2019). With new base rates effective May 1, 2018, Schedule 93 expires ($15.0 million), offsetting the increase in pro forma net power supply costs ($16.6 million), for a bill impact of $1.6 million.

[4] As discussed further in Section IV. "EOP Rate Base Study" of my testimony, the Company has requested an adjusted capital structure of 50% Equity / 50% Debt, which results in the proposed cost of capital of 7.76%.

annual reporting to the Commission begin in column (1.01) on page 4 and continue through column (2.18) on page 6. Individual Pro Forma adjustments are shown on pages 7 and 8 in columns (3.01) though (3.14). The last column on page 8, labeled "Non-Energy Pro Forma Sub-Total" is the subtotal of the previous columns (1.00) through (3.14), and produces the Traditional Pro Forma Study Non-Energy net operating income (NOI), total rate base, and revenue requirement totaling $20,892,000.

Turning to page 9, adjustment 4.00 "Pro Forma Power Supply and Transmission Revenues" is the last pro forma adjustment included ($16.609 million), prior to the "Pro Forma Including PS Total," column, totaling $37.501 million overall Pro Forma revenue requirement, as shown on page 1. The final two columns shown on page 9, are provided for informational purposes, which show the impact of the expiration of tariff Schedule 93 ($14.976 million), and the incremental difference of column 4.00 "Pro Forma Power Supply & Transmission Revenues," net of the expiration of "Schedule 93," showing the incremental bill increase of $1.652 million (or .32%).

The testimony that follows explains each of the electric Commission Basis, restating and Pro Forma adjustments. The Company has also provided workpapers, both in hard copy and electronic formats, which include additional details related to each of these adjustments.

**Electric Standard Commission Basis and Restating Adjustments**

**Q. Please explain each of the Commission Basis and restating adjustments included, starting on page 4 of Exh. EMA-2), the reason for the adjustment and its**

**effect on the Washington electric net operating income and/or rate base for the historical test period?**

A. Starting on page 4, Column **(1.00)** the **Results of Operations** reflect the Company's actual operating results and total net rate base experienced by the Company for year ending December 2016 on an AMA basis. Columns following the Results of Operations column (1.00), (columns (1.01) – (2.18)) mainly reflect normalizing and restating adjustments necessary to restate the actual results based on prior Commission orders, reflect appropriate annualized expenses, correct for errors, or remove prior period amounts reflected in the year ending December 2016.

The first adjustment, column **(1.01)** on page 4, entitled **<u>Deferred FIT Rate Base,</u>** adjusts the accumulated deferred federal income tax (ADFIT) rate base balance included in the Results of Operations column (1.00) to the adjusted ADFIT balance reflected on an AMA basis, as shown within my workpapers provided with the Company's filing.

ADFIT reflects the deferred tax balances arising from accelerated tax depreciation (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated Cost Recovery, or MACRS, repairs deduction and bonus depreciation), bond refinancing premiums, and contributions in aid of construction.

The effect on Washington rate base for this adjustment is an increase of $806,000. An increase to Washington net operating income of $8,000 is due to the Federal income tax (FIT) expense on the restated level of interest on the change in rate base[5].

[5] The net effect of Federal Income Tax (FIT) expense on the restated level of interest expense due to a change in rate base, is shown within <u>each</u> individual adjustment. The restated debt interest impact per individual rate base adjustment can be seen on line 28 of Exh. EMA-2.

**Deferred Debits and Credits,** column **(1.02)**, is a consolidation of previous Commission Basis or other restating rate base adjustments and their net operating income (NOI) impact. The net impact on a consolidated basis of this adjustment decreases net operating income (NOI) by a total of $8,000.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from actual results based on prior Commission orders, and are explained below. For consistency with prior rate case filings, a description of each adjustment is included below.

The following items are included in the consolidated adjustment:

- **Colstrip 3 AFUDC Elimination** reflects the reallocation of rate base and depreciation expense between jurisdictions. In Cause Nos. U-81-15 and U-82-10, the UTC allowed the Company a return on a portion of Colstrip Unit 3 construction work in progress ("CWIP"). A much smaller amount of Colstrip Unit 3 CWIP was allowed in rate base in Case U-1008-144 by the Idaho Public Utilities Commission ("IPUC"). The Company eliminated the AFUDC associated with the portion of CWIP allowed in rate base in each jurisdiction. Since production facilities are allocated on the Production/Transmission formula, the allocation of AFUDC is reversed and a direct assignment is made. The rate base adjustment reflects the average-of-monthly-averages amount for the test period. No adjustment from that recorded within results of operations is necessary.

- **Colstrip Common AFUDC** is associated with the Colstrip plants in Montana, and impacts rate base. Differing amounts of Colstrip common facilities were excluded from rate base by this Commission and the IPUC until Colstrip Unit 4 was placed in service. The Company was allowed to accrue AFUDC on the Colstrip common facilities during the time that they were excluded from rate base. It is necessary to directly assign the AFUDC because of the differing amounts of common facilities excluded from rate base by this Commission and the IPUC. In September 1988, an entry was made to comply with a Federal Energy Regulatory Commission ("FERC") Audit Exception, which transferred Colstrip common AFUDC from the plant accounts to Account 186. These amounts reflect a direct assignment of rate base for the appropriate average-of-monthly-averages amounts of Colstrip common AFUDC to the Washington and Idaho jurisdictions. Amortization expense associated with the Colstrip common AFUDC is charged directly to the Washington and Idaho jurisdictions through Account 406 and is a component of the actual results of operations. The rate base amount is also included in the results of operations accurately reflecting the average-of-monthly-averages amount for the test period. No adjustment from that recorded within results of operations is necessary.

- **Kettle Falls Disallowance** reflects the Kettle Falls generating plant disallowance ordered by this Commission in Cause No. U-83-26. The disallowed investment and related depreciation, FIT expense, accumulated depreciation and accumulated deferred FIT on an AMA basis are accurately reflected in the results of operations column, removing these amounts from actual results of operations. No adjustment from that recorded within results of operations is necessary.

- **Settlement Exchange Power** reflects the rate base associated with the recovery of 64.1% of the Company's investment in Settlement Exchange Power. The 64.1% recovery level was approved by the Commission's Second Supplemental Order in Cause No. U-86-99 dated February 24, 1987. Amortization expense and deferred FIT expense recorded during the test period are accurately reflected in results of operations. The production rate base and accumulated deferred FIT amounts within results of operations are reflected on a twelve-month ending December 31, 2016 test period AMA basis. No adjustment from that recorded within results of operations is necessary.

- **Restating CDA Settlement Deferral** reflects the net assets and DFIT balances associated with the 2008/2009 past storage and §10(e) charges deferred for future recovery are reflected on a twelve-month ending December 31, 2016 test period AMA basis within results of operations. A ten-year amortization expense, as approved in Docket No. UE-100467, of the CDA Settlement Deferral is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Restating CDA/SRR (Spokane River Relicensing) CDR Deferral** the net assets associated with the CDA Tribe settlement 4(e) Spokane River relicensing conditions deferred for future recovery are reflected on a twelve-month ending December 31, 2016 test period AMA basis within results of operations. A ten-year amortization expense of the CDA/SRR CDR Deferral, as approved in Docket No. UE-100467 is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Restating Spokane River Deferral** reflects the net asset and DFIT balances related to the Spokane River deferred relicensing costs deferred for future recovery are reflected on a twelve-month ending December 31, 2016 test period AMA basis within results of operations. A ten-year amortization expense of the Spokane River Deferral, as approved in Docket No. UE-100467, is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Restating Spokane River PM&E Deferral** reflects the net asset and DFIT balances related to the Spokane River deferred PM&E costs deferred for future recovery are reflected on a twelve-month ending December 31, 2016 test period AMA basis within results of operations. A ten-year amortization expense of the Spokane River PM&E Deferral, as approved in Docket No. UE-100467, is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Restating Montana Riverbed Lease** reflects the net asset and DFIT balances related to the Spokane River deferred PM&E costs deferred for future recovery are reflected on a twelve-month ending December 31, 2016 test period AMA basis within results of operations. In the Montana Riverbed lease settlement, the Company agreed to pay the State of Montana $4.0 million annually beginning in 2007, with annual inflation adjustments, for a 10-year period for leasing the riverbed under the Noxon Rapids Project and the Montana portion of the Cabinet Gorge Project. The first two annual payments were deferred by Avista as approved in Docket No. UE-072131. In Docket No. UE-080416 (see Order No. 08), the Commission approved the Company's accounting treatment of the deferred payments, including accrued interest, to be amortized over the remaining eight years of the agreement starting on January 1, 2009. The 10-year amortization of the first two annual payment deferral expired on December 31, 2016. The ten-year amortization expense of the Montana Riverbed Lease Deferral, as approved in Docket No. UE-072131, is accurately reflected in results of operations. An adjustment to reflect the correct lease expense for 2016 increased expense $4,000.

- **Customer Advances** decreases rate base for money advanced by customers for line extensions, as they will be recorded as contributions in aid of construction at some future time. No adjustment from that recorded within results of operations is necessary.

- **Customer Deposits** reduces electric rate base by the average-of-monthly-averages of customer deposits held by the Company, as ordered by this Commission in Docket UE-090134. The reduction to rate base is accurately reflected in results of operations. Therefore no adjustment is necessary to rate base. The corresponding interest paid on customer deposits is reclassified to utility operating expense, at the current UTC interest rate of 0.49%. The effect on Washington is an increase in expense of $8,000.

In summary, as noted above, the net impact on a consolidated basis of the adjustments described above decreases Washington net operating income by $8,000. (Adjustment (3.09) Pro Forma Deferred Debits, Credits & Regulatory Amortizations, explained below, adjusts certain items listed above to reflect pro forma (May 1, 2018 –

April 30, 2019) levels of deferred debits and credit balances and amortization expense as ordered in prior cases.)

**Working Capital**, column (1.03), restates the working capital balance reflected in the Company's Results of Operations column (1.00), to the adjusted working capital balance. The Company uses the Investor Supplied Working Capital (ISWC) methodology to calculate the amount of working capital reflected in its actual results of operations. This method is consistent with that incorporated in the Company's last approved electric general rate case, Docket No. UE-150204. In addition, ISWC was revised to properly reflect the effect of Investment Tax Credit (ITC) in 2016 on the Company's Nine Mile capital project, which went into service in mid-2016. The net effect of adjustments to ISWC from that recorded per results of operations at December 31, 2016, decreases net rate base by $3,006,000, and decreases net operating income by $30,000 due to the FIT expense of the restated level of interest on the change in rate base[6].

**Eliminate B & O Taxes**, column (2.01), eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Washington customers. The adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. B & O taxes are passed through on a separate schedule, which is not part of this proceeding. The effect of this adjustment is to decrease Washington net operating income by $96,000.

[6] The net effect of Federal Income Tax (FIT) expense on the restated level of interest expense due to a change in rate base, is shown within each individual adjustment. The restated debt interest impact per individual rate base adjustment can be seen on line 28 of Exh. EMA-2).

**<u>Restate Property Tax</u>**, column (2.02), restates the accrued property tax during the test period to actual property tax paid during 2016. Property tax expense for 2016 was based on actual plant balances as of December 31, 2015. The effect of this adjustment increases Washington net operating income by $163,000. Adjustment (3.06) Pro Forma Property Tax, explained below, increases property tax expense to reflect the levels of expense expected during the rate year, based on planned plant balances as of December 31, 2017.

**<u>Uncollectible Expense</u>**, column (2.03), restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment decreases net operating income by $859,000.

**<u>Regulatory Expense</u>**, the last adjustment on page 4, column (2.04), restates recorded regulatory expense for twelve-months-ended December 31, 2016, to reflect the UTC assessment rates applied to revenues for the test period and the actual levels of FERC fees paid during the test period. The effect of this adjustment decreases net operating income by $5,000.

**Q. Please turn to page 5 and explain the adjustments shown there.**

A. Turning to page 5, the first adjustment in column (2.05) **<u>Injuries and Damages</u>**, restates accrued injuries and damages expense with a six-year rolling average of injuries and damages payments not covered by insurance. As a result of the Commission's Order in Docket No. U-88-2380-T, the Company changed to the reserve method of accounting for injuries and damages not covered by insurance. The effect of this adjustment decreases net operating income by $98,000.

**FIT/DFIT/ITC/PTC Expenses**, column (2.06), adjusts the FIT and DFIT calculated at 35% within Results of Operations for the year ending December 31, 2016. This adjustment also adjusts the appropriate level of production tax credits and investment tax credits on qualified generation. The net FIT and production tax credit adjustment decreases net operating income by $69,000.

**Office Space Charged to Non-Utility**, column (2.07), removes a portion of the office space costs[7] based on the relationship of labor hours charged to subsidiary/non-utility activities by employee compared to total labor hours by employee. These percentages are applied to the employees' office space (expressed in square feet) and multiplied by office space costs/per square foot. This restating adjustment is made as a result of the Commission's Third Supplemental Order in Docket No. U-88-2380-T. This adjustment removes the portion of expense that has not already been reflected in the test period as non-utility. The effect of this adjustment increases net operating income by $20,000.

**Restate Excise Taxes**, column (2.08), removes the effect of a one-month lag between collection and payment of taxes. The effect of this adjustment increases net operating income by $40,000.

**Net Gains/Losses**, column (2.09), reflects a ten-year amortization of net gains realized from the sale of real property disposed of between 2007 and December 31, 2016. This restating adjustment is made as a result of the Commission's Order in Docket No. UE-050482. The effect of this adjustment increases net operating income by $61,000.

**Weather Normalization**, column (2.10), normalizes weather sensitive kWh sales

[7] Office space is comprised of office building operating and fixed costs, utilities, administrative, security, HVAC, depreciation and property taxes, as well as other costs related to employee use of phones, laptops, etc.

by eliminating the effect of temperature deviations above or below historical norms. Company witness Ms. Knox is sponsoring this adjustment. The effect of this particular adjustment increases net operating income by $825,000.

**Eliminate Adder Schedule Adjustments**, column (2.11), removes the impact of the adder schedule revenues and related expenses, such as Schedule 59 Residential Exchange credit, Schedule 75 Decoupling Rebate/Surcharge, Schedule 91 Tariff Rider (DSM), Schedule 92 Low Income Rate Assistance Program Rate, Schedule 93 ERM rebate, Schedule 94 BPA rebate, Schedule 95 Optional Renewable and Schedule 98 REC Revenue Surcharge/Rebate since these items are recovered/rebated by separate tariffs and, therefore, are not part of base rates. There is no effect of this adjustment on Washington net operating income, as the adjustment to expense is equal to the adjustment to revenue. Ms. Knox is sponsoring this adjustment.

**Miscellaneous Restating Non-Utility/Non-Recurring Expenses,** column (2.12), is the final adjustment on page 5**.** This adjustment removes a number of non-operating or non-utility expenses associated with dues and donations, etc., included in error in the test period actual results, and removes, reclassifies or restates other expenses incorrectly charged between service and or jurisdiction. The Company has removed or restated certain Director and Officer related expenses. Director meeting expenses were reduced by $375,000 expense to reflect removal of 50% of director meeting expenses were excluded from utility operations, per Docket No. UE-090134. The Company has also removed the utility-portion of the Company's Long Term Incentive Plan (LTIP) related to restricted shares expense, as ordered in Docket No. UE-150204 in the amount of $654,000 expense. Finally, 10% of total Directors' and Officers' insurance expense has been removed to reflect the non-utility/subsidiary portion. The net reduction of these expenses is approximately $1,075,000 in expense or a reduction of $969,000 in net operating income. Adjustment (3.12) Pro Forma Director Fee Expense as explained below, proposes to include utility expense as actually recorded on the Company's books, based on annual surveys of the Board of Directors of their time split between utility/non-utility operations.

**Q. Please continue an explanation for adjustments on page 6.**

A. The first adjustment on page 7, column (2.13) **Eliminate WA Power Cost Deferral,** removes the effects of the financial accounting for the Energy Recovery Mechanism (ERM.) The ERM normalizes and defers certain net power supply and transmission revenues and expenses pursuant to the Commission-approved deferral and recovery mechanism. The adjustment removes the ERM rebate revenue as well as the deferral and amortization amounts and certain directly assigned power costs and net transmission costs associated with the ERM. The effect of this adjustment increases net operating income by $4,386,000.

**Nez Perce Settlement Adjustment**, adjustment column (2.14), reflects a decrease in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe in 1999 to settle certain issues regarding previously owned hydroelectric generating facilities of the Company. This adjustment directly assigns the Nez Perce Settlement expenses to the Washington and Idaho jurisdictions. This is necessary due to differing regulatory treatment in Idaho Case No. WWP-E-98-11 and Washington Docket No. UE-991606. This restating adjustment is consistent with prior dockets since Docket No. UE-011595. The effect of this adjustment increases net operating income by $3,000.

**Restating Incentive Expense,** column (2.15), restates actual O&M incentive compensation expense recorded in 2016 to reflect a six-year average (2011-2016) of target payout. Target payout is based on salary levels in effect as of December 31, 2016. The net effect of this adjustment (including both executive and non-executive) increases net operating income by approximately $407,000.

For executive officers, the six-year average payout of O&M metrics related to efficiencies in cost management (O&M cost-per-customer), customer service and reliability have averaged approximately 106%. Incentive compensation related to financial metrics are excluded from the Company's filing with expenses borne by shareholders. For non-executive officers, the six-year average of incentive compensation payout is 109% for O&M metrics designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. This methodology is consistent with that approved in Dockets UE-150204 and UG-150205. Adjustment (3.05) Pro-Forma Incentive Expenses adjusts incentives based on pro forma labor expense. Additional descriptions are also provided there of overall compensation and components of the executive and non-executive incentive compensation.

**Normalize CS2/Colstrip Major Maintenance,** column 2.16, includes an adjustment to normalize major maintenance expense associated with Avista's Colstrip/Coyote Springs II (CS2) thermal projects. In Order 05, page 56, paragraph 153 of Docket No. UE-150204, the Commission ordered the Company, for regulatory purposes, to normalize and recover its major maintenance expense associated with these plants over a three-year period for Colstrip and four-year period for CS2 to match the major maintenance cycles for each plant.

In 2014, Colstrip major maintenance was $1.9 million system. There was no major maintenance in 2015. In 2016, Colstrip major maintenance occurred totaling approximately $3.6 million system.[8] For regulatory purposes consistent with UE-150204, the regulatory amortization expense level to include in 2016 totals $1.8 million on a system basis. (One-third of 2014 Colstrip major maintenance, or $627,000 million, plus one-third of the 2016 Colstrip major maintenance, or $1.2 million system, totals $1.8 million.)

Adjustment 2.16 reflects this reduction of $1.17 million for Washington's share. The net effect of this adjustment increases net operating income by approximately $763,000.[9]

**Restate Debt Interest,** column (2.17), restates debt interest using the Company's pro forma weighted average cost of debt included in the Traditional Pro Forma Study of 2.89%, on the Results of Operations level of rate base shown in column (1.00) only, resulting in a revised level of tax deductible interest expense on actual test period rate base. The Federal income tax effect of the restated level of interest for the test period increases Washington net operating income by $860,000.[10]

The Federal income tax effect of the restated level of interest on all other rate base adjustments included in the Company's filing are included and shown as an income impact of each individual rate base adjustment described elsewhere in this testimony.

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[8] For Colstrip, major maintenance occurs two out of every three years. Major maintenance occurred in 2016, is currently underway for 2017, with no maintenance planned in 2018.

[9] There were no major maintenance expense projects for CS2 during 2013-2016, therefore, no adjustment is required for CS2.

[10] The EOP Rate Base Study, which is the basis of the Company's proposed revenue increase, includes the Company proposed equity layer of 50%, causing the pro forma weighted average cost of debt to equal 2.81%. This higher weighted cost of debt results in a restate debt adjustment that increases net operating income $455,000, rather than the restating adjustment noted above of $860,000.

**<u>Authorized Power Supply,</u>** the final adjustment on page 6, column (2.18), was prepared under the direction of Company witness Mr. Johnson. This adjustment restates the actual power supply costs for the test year ending December 31, 2016 to the level currently authorized in Case No. UE-150204[11]. This adjustment results in a reduction in Washington operating net income of $7,696,000.

**Q. Please provide an explanation for the final column on page 6, "Restate Total".**

A. The last column on page 7, entitled **Restated Total**, subtotals all the preceding columns (1.00) through column (2.18). These totals represent actual operating results and rate base plus the standard normalizing adjustments that the Company includes in its annual Commission Basis reports. However, the Restated Total column does not represent December 31, 2016 test period results of operation on a normalized commission basis as filed with the WUTC on April 28, 2017. Two differences exist here: 1) inclusion of proposed (Pro Forma) cost of debt (pro forma versus CBR cost of debt) impacting Adjustment 2.17 above; and 2) Authorized (ERM) Power Supply (Adj 2.18 above) versus revised Authorized Power Supply (CB) which included the updated Production/ Transmission (P/T) ratio.

[11] This includes Washington's share using the current authorized Production/Transmission Ratio (P/T Ratio) of 64.71%. Increases to power supply expense related to updating ERM related costs, including the updated P/T ratio of 65.73%, is included in Pro Forma Power Supply & Transmission Revenue (ERM Related) adjustment 4.00.

**<u>Electric Pro Forma Adjustments</u>**

**Q. Please now turn to pages 7 through 9 and explain what is provided there.**

A. Starting on page 7 are individual "Pro Forma" adjustments, (3.01) through (3.14), proposed by the Company for the rate effective period May 1, 2018 – April 30, 2019. Each of these adjustments are described below.

**<u>Pro Forma Transmission/Power Supply/Non-ERM Revenue and Expense,</u>** column (3.01), includes pro forma transmission <u>expenses</u> (sponsored by Company witness Mr. Schlect) and power supply (<u>non-ERM related) revenues and expenses</u> (sponsored by Mr. Johnson). Pro forma transmission and power supply revenues and expenses have been segregated into two separate adjustments: those representing 1) costs tracked through the Company's ERM (Pro Forma adjustment 4.00); and 2) those costs <u>not</u> tracked through the ERM (Pro Forma Adjustment 3.01).

The pro forma power supply revenue and expense accounts included in this adjustment (not tracked through the ERM) relate to FERC accounts 453 (revenue from sales of water and water power) and 536 (water and power expense). Mr. Johnson sponsors the changes in these accounts. The transmission expense accounts included in this adjustment (not tracked through the ERM) relate to FERC accounts 556 (system control and dispatch) and 565 (transmission of electric by others). Mr. Schlect sponsors the changes in these accounts. This adjustment calculates the Washington jurisdictional share of those adjustments. The net effect of this adjustments decreases Washington net operating income by $66,000.

**Q. The next four adjustments (3.02) through (3.05) relate to pro forma labor and benefit adjustments. Prior to addressing each of the adjustments, please provide an overview of the Company's total compensation philosophy.**

A. Avista is committed to providing total compensation to employees that will attract and retain qualified people required to meet the needs and expectations of all utility stakeholders, including but not limited to, customers, shareholders and regulators. To that end, the Company provides employees with cash compensation (base pay and variable pay in the form of pay-at-risk incentive compensation) and a comprehensive benefit package including medical and retirement. The overall package is designed to meet the following goals:

- Clearly identify the specific measures of Company performance that are likely to create long-term value for the Company's customers and shareholders;
- Keep employees focused on cost control, customer satisfaction, reliability and operational efficiencies by awarding variable pay for meeting pre-determined metrics;
- Promote a culture of safety;
- Pay competitively compared to others within our market;
- Reward outstanding performance; and
- Align elements of the incentive plans among all Company employees, including executive officers.

Each component is carefully considered within the overall package in order to provide total compensation which will be cost-effective for the Company, as well as, attract and retain employees. Compensation components within the overall package may be adjusted over time to achieve the goal of recruiting and retaining qualified employees. The Company generally targets overall compensation levels within the range that is 15% above or below the median of Avista's peer group.

**Q. Please now turn to adjustment (3.02) Pro-Forma Labor Non-Exec on page 7 of Exh. EMA-2.**

A. **Pro Forma Labor Non-Exec,** column (3.02)**,** reflects changes to test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in adjustment (3.03). For non-union employees, the 3% increase for March 2017 represents actual increases already in effect. In May 2017, the Board of Directors voted to approve a minimum level of salary increases of 3% for March 2018. Union employee increases are made in accordance with contract terms. The current contract with the IBEW Union 77 (Washington/Idaho) expires on March 25, 2019. The methodology behind this adjustment is consistent with Docket No. UE-150204 and UG-150205. The net effect of this non-executive labor adjustment decreases net operating income by $1,862,000 for electric operations.

This adjustment reflects changes in base pay, which together with pay-at-risk is designed to provide competitive compensation in the market place. The level of base pay is determined based on position qualifications such as level of education, professional designations or certifications, experience, roles and responsibilities, and the market. Avista participates in numerous confidential salary surveys provided by third-party consulting firms which compare Avista's pay programs and structure to other organizations in the utility industry, as well as other industries, regionally and nationally. Salary surveys are part of the input in the determination of salary increases and salary range updates (minimum, mid-point and maximum), as well as benchmarking jobs to market data. Avista benchmarks many jobs within the Company and reviews market data to determine if the salary range midpoints still accommodate the new estimated values established by the benchmarking process. Based on the information provided in these surveys, salary recommendations are presented to the independent Compensation Committee of the Board of Directors for their consideration and approval. The Compensation Committee can choose to grant higher or lower salary adjustments, based on the available market data.

**Pro Forma Labor-Executive**, column (3.03), annualizes actual salary levels effective as of March 1, 2017. This results in an increase in net operating income of $21,000 over and above what was in effect year ending December 31, 2016. Base pay is allocated approximately 90% to utility operations and 10% to non-utility operations based on actual timesheet allocations as of December 31, 2016 per order UE-150204/UG-150205.

As with all components of executive officer compensation, the Compensation Committee of the Board of Directors (Board) determines the appropriate level of base salary. The Board considers several internal factors such as individual and Company performance goals, succession planning, job complexity, experience and breadth of knowledge in the determination of base pay. Similar to non-executive compensation, the Board also utilizes external peer group data to benchmark its executives against a group of companies with similar business profiles, similar revenue size and market capitalization. These companies can reasonably be assumed to be the companies with which we compete for talent.

**Pro Forma Employee Benefits**, column (3.04), adjusts the year ending December 31, 2016 pension and medical expense to include the net changes in the Company's 401(k) and medical insurance expense expected during the rate year. In total, this adjustment reflects the change in total employee benefit expense on a system level from $40.5 million to $39.8 million (O&M). The total net effect of this adjustment is a reduction to Washington electric expense of $359,000, increasing net operating income $234,000.

The Company offers a comprehensive benefit plan for employees. Employees have several choices to elect benefits, such as medical and life insurance, so they can determine the best fit for their circumstances. The plans are designed to be competitive with the overall market practices and are in place to attract and retain qualified employees. Each component is carefully evaluated in order to ensure the appropriate level of overall benefits within the overall compensation package. To aid in benchmarking our benefit plan, Avista participates in a comprehensive benefit evaluation study, BENEVAL, performed by an independent actuarial company, Willis Towers Watson. Similar to cash compensation, the Company generally targets the level of benefits it offers to be within +/- 15% of the market median. The table below illustrates the breakdown of components within this adjustment:

| Adjustment | System | O&M | Washington - Elec | Washington - Gas |
|---|---|---|---|---|
| Retirement | (2,848,000) | (1,639,000) | (777,000) | (381,000) |
| Medical | 1,531,000 | 882,000 | 418,000 | 205,000 |
| Total | (1,317,000) | (757,000) | (359,000) | (176,000) |

**Q. Please describe the Retirement Portion of the Employee Benefit adjustment.**

A. As illustrated in the table above, the change in pension expense from the year ending December 31, 2016 to that expected during the rate year is a reduction of approximately $1.6 million (O&M) system, and $777,000 Washington Electric, $381,000 Washington Natural Gas. Pension expense is determined by an independent actuary in accordance with Accounting Standard Codification 715 (ASC-715). The primary contributor to this reduction in expense is related to expected return on assets and the discount rate. Assumptions utilized in the calculation are presented to and approved by the Board of Directors annually. In addition, these calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other Companies. The Company has included in this case the most recent estimates provided by our actuary. We anticipate updates for 2018 to be available sometime in the third or fourth quarter of 2017, and the Company will adjust pension expense at that time.

**Q. Please describe the changes to the Company's retirement plan.**

A. Effective January 1, 2014, the defined benefit pension plan is closed to all non-union employees hired or rehired on or after January 1, 2014.[12] All actively employed non-union employees that were hired prior to January 1, 2014, and were covered under the defined benefit pension plan at that time, will continue accruing benefits as originally specified in the plan. A defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the defined contribution plan the Company will provide a non-elective contribution as a percentage of each employee's pay based on his or her age. This defined contribution is in addition to the existing 401(k) contribution where Avista matches a portion of the pay deferred by each participant. In addition to the above changes, the Company also revised our lump sum calculation for non-union retirees under the defined benefit pension plan to provide non-union participants who retire on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates.

[12] Changes were applicable to Local Union 659 (Oregon) effective April 1, 2014.

This reduces the future costs and risks to the Company of funding and managing the annual pension benefit (annuity) for retirees.

**Q. Please now describe the role employee medical benefits play within the Company's overall employee compensation.**

A. Avista sponsors a self-funded medical plan that provides various levels of coverage for medical, dental and vision as a portion of employee benefits. The various components within the medical plan (co-pays, deductibles, premium sharing, etc.) are carefully evaluated in order to maintain an appropriate level of medical benefits within the benefit plan and ultimately overall employee compensation. The Company's medical adjustment encompasses health insurance expense for active employees as well as post-retirement medical (FAS 106) for retired employees within the plan. The total medical <u>expense</u> portion of this adjustment ($418,000 Washington Electric and $205,000 Washington Natural Gas) adjusts for the estimated medical-related costs expected during the rate year, over and above the year ending December 31, 2016.

**Q. Please provide an overview of how medical premiums for the Company are set.**

A. Medical premiums[13] for the Company are set annually by an independent consultant, Mercer.[14] Premiums are estimated based on medical trend, which is a combination of utilization (the pattern of use or intensity of services used for a particular timeframe), and the estimated increase in the costs to treat patients from one year to the

[13] In this context, "premium" is defined as total medical costs including both the Company and employee contribution.
[14] Mercer is currently the world's largest human resources consulting firm, with more than 20,500 employees, based in more than 40 countries.

next. Costs are generally related to the type of medical services, such as outpatient procedures, office visits, physical therapy and emergency room visits, prescription drugs, and medical equipment, among other things. The premium estimate is the basis for the medical cost estimate provided by Mercer. Mercer takes into consideration Company population profile (number and composition of participating employees), estimated medical and prescription costs, and laws/regulation in order to determine the appropriate premium.

**Q. What measures has the Company implemented to keep medical costs down?**

A. Avista encourages employees to take responsibility for their health care by offering various wellness programs, biometric screening, health risk assessment tools, discounted gym memberships and on-site exercise classes and facilities.

To keep office visit costs down, we offer access to phone or web-based 24/7 telemedicine services and an on-site clinic. We have limited our exposure to large claims through an insurance policy with annual stop-loss limits of $250,000 per person. When employees do require medical care for catastrophic conditions, we have a case management program managed by a third-party administrator to help manage these costs. To keep prescription drug costs down, the Company has contracted with specialty pharmacies who help participants determine the most economic treatment options. In addition, the Company has made the following changes to the medical plan offered to employees:

- For non-union employees hired or rehired on or after January 1, 2014, and Local Union 659 employees hired or rehired on or after April 1, 2014, upon retirement the Company no longer provides a contribution towards his or her medical premiums. The Company will provide access to the retiree medical plan, but the retiree will pay the full cost of premiums upon retirement.

- Manage Utilization of Specialty Drugs – The Company reviews measures to lower the cost of prescription drugs including requiring prior authorization, and implementing step therapy.

- Beginning January 1, 2020, the method for calculating health insurance premiums for the following employee groups will change: non-union retirees, Local Union 659, hired or rehired after April 1, 2014 under age 65, and active non-union employees hired or rehired after April 1, 2014 under age 65. Revisions will result in separate health insurance premium calculations for retirees and active employees beginning January 1, 2020.

**Q. What steps is Avista taking going forward to mitigate cost increases?**

A. Beginning in 2017, Avista offered a self-insured High Deductible Health Plan ("HDHP") in addition to the current self-insured plan. The HDHP requires plan participants to pay all costs of medical care up to defined deductible limits. This plan will enforce the message to participants to manage their own health with an array of tools to assist them in becoming better consumers. Over time we expect this plan to result in lower overall medical costs to the Company. The level of cost savings will be dependent upon, among other things, the number of employees that choose this plan, and the level of utilization of medical care for those employees (i.e., the overall medical expense to the Company under the High Deductible plan versus the old plan for those particular employees and their families). The level of cost savings from the HDHP is expected to be minimal initially, and will be unknown for the longer-term until we have actual experience under the plan. The Company is also working closely with Mercer to evaluate and develop alternative strategies to reduce and/or maintain medical costs going forward, including:

- Plan Review – thorough review of plan metrics to evaluate any potential plan inefficiencies and target disease-management programs.

- Consideration of narrow or custom provider networks – seeking out the best

> quality, highest value hospital or physician group may result in lower unit costs and better long-term outcomes. The trade-off of less choice for plan participants will need to be weighed against the financial returns these networks offer.

In summary, the Company is taking proactive steps to reduce medical cost increases in the coming years, which the Company believes will help to offset some of the increases in medical expense going forward.

**Pro Forma Incentive Expenses,** column (3.05), pro forms increases in variable pay/incentive compensation expense, from the year ending 2016 to the rate year amounts in effect, by approximately 2.8% per year, consistent with base pay increases in adjustment 3.02 Pro-Forma Labor Non-Exec. The net impact of this adjustment decreases net operating income by $77,000.

The salary surveys conducted by third-party consulting firms, utilized for setting base pay, also include a variable pay component in order to benchmark cash compensation as a whole. Variable pay or incentive compensation, typically expressed as a percentage of base pay, represents the portion of pay that is at-risk. This portion of cash compensation is only payable on the achievement of certain performance metrics. Employees receive this portion of compensation based on the achievement of metrics related to operational efficiencies and cost control, customer satisfaction, and reliability within the system. Metrics are designed to be reasonably achievable with strong management performance. Maximum incentive payout levels, however, are designed to be difficult to achieve given historical performance and forecasted results at the time the metrics are approved. The amount of variable compensation varies by job position based upon the individual employee's pay grade level, and is designed to be competitive with comparable job positions in companies with similar business profiles. As an example, Avista's average percent target opportunity for exempt, non-management employees is approximately 9% compared to approximately 10.0% for General industry and 12% for the Energy Industry[15]. Approximately 85% of companies in the energy sector offer some form of variable pay within their cash compensation structure. Through the inclusion of a variable pay as part of overall cash compensation, the Company has the ability to meet our goal of being within the +/- 15% of market median for cash compensation.

It is important to note that the employee incentive compensation is not additional compensation above what is competitive with other similar utilities. Rather, incentive compensation is a method to provide the appropriate competitive level of cash compensation, while controlling costs and keeping employees motivated and focused on measures which provide long term customer benefits. If the amount of incentive compensation was reduced or eliminated, base pay would need to be increased to maintain the level of compensation required to remain competitive.

**Q. Please provide an overview of the Company's non-executive employee short-term incentive plan (Non-Executive Employee STIP).**

A. In accordance with the Company's overall compensation design to align elements of incentive plans among all Company employees including executives, the Non-Executive Employee STIP plan has essentially the same stated goals as the Short-Term Incentive Plan for executives (Executive STIP). Both plans provide incentives and focus employees on stated goals while recognizing and rewarding employees for their contributions toward achieving those goals. The components of the Non-Executive

[15] Based on 2016 General Industry Salary Budget Survey Results, Willis Towers Watson, pages 219 and 220.

Employee STIP are all operational in nature, including cost containment on a per customer basis. The weighting of each component is as follows: 60% O & M Cost-Per-Customer, 15% Customer Satisfaction, 15% Reliability Index and 10% Response Time.[16]

**Q. Please briefly describe the Executive STIP.**

A. The Executive STIP is designed to align the interests of executives with both customer and shareholder interests in order to achieve overall positive operating and financial performance for the Company. The Executive STIP has four operational components, plus two earnings per share (EPS) components. The total amount associated with utility operational components is 40% and is broken down as follows: 20% O&M Cost-Per-Customer, 8% Customer Satisfaction, 8% Reliability, and 4% Response Time. The EPS components account for 60% of the total opportunity and are broken out into 50% utility EPS and 10% non-utility EPS. <u>Only the operational components (40%) are proposed to be included in retail rates.</u> Customers benefit from these metrics that are designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. The remaining 60% related to EPS targets is borne by shareholders.

**Q. What portion of the Short Term Incentive Plans have been included in this case?**

A. The Company has included 100% of the Non-Executive Employee STIP and 40% of the Executive STIP (excluding those metrics related to EPS targets) in this case. All incentive compensation included in this case directly benefits customers either in cost containment and efficiencies, operationally via the reliability index and response time

[16] Effective January 1, 2017, the weighting of each component has changed as follows: 50% O & M Cost-Per-Customer, 20% Customer Satisfaction, 20% Reliability Index and 10% Response Time.

metrics, or customer satisfaction as measured via the Voice of the Customer Survey. By focusing employees on effective management of O&M costs, we are able to maintain or reduce charges to customers in future rate cases. The Company has excluded all incentive pay related to the EPS portion of Executive STIP. In addition, a proportionate share of incentive pay for employees (in the same percentage as employee labor) related to non-utility operations has also been excluded from this case. Therefore, the appropriate portion of incentives related to Washington utility operations has been included in this case.

**Q. Please describe the Executive Long Term Incentive Plan (LTIP).**

A. The Executive Officer Long Term Incentive Plan (LTIP) is comprised of two components, which serve two different purposes.[17] Performance Shares account for 75% of the plan with metrics related to Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). The purpose for this portion of the plan is to provide a direct link to the long-term interests of shareholders by assuring that performance shares will be paid only if the Company attains specified financial performance levels. This portion of the plan was modified in 2014 to include both Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). In previous years, vesting of performance-based equity awards were 100% contingent on the Company's Total Shareholder Return (TSR) relative to our peer group over a three-year period. Under the new design, two-thirds of the awards are contingent on TSR relative to our peers, and one-third is measured by our CEPS over a

[17] As with all other components of the executive compensation, the Compensation Committee determines all material aspects of the long-term incentive – who receives the award, the amount of the award, the timing of the award, as well as any other aspects of the award that may be deemed material.

three-year period. The Company has excluded the costs associated with the Performance Share portion of the LTIP from the revenue requirement in this case.

Restricted Stock Unit (RSU) awards account for 25% of the LTIP and vesting is based on a continuation of service by the employee. The purpose for this portion of the plan is to provide an incentive for employees to remain with the Company. The long-term nature of large-scale utility projects spanning multiple years are completed more efficiently with experienced, consistent leadership. In addition, it is the Company's policy to promote from within when possible, preserving the values inherent in our culture that drive customer satisfaction, reliability of service, etc. Employees with a long tenure of employment with the Company are well versed in the Company's culture and tend to continue to cultivate the values embedded within Avista. The Company continues to believe RSUs are a key component in retention, however, per Order No. 05 UE-150204/UG-150205 the Company has removed the impact of the RSUs from this case. See adjustment 2.12 as described above.

**Q. Please continue with your discussion on pro forma adjustments included on page 7.**

**A. Pro Forma Property Tax, c**olumn (3.06), restates the 2016 level of property tax expense included in adjustment (2.02) Restate 2016 Property tax, to the level of property tax expense the Company will experience during the rate year. The property on which the tax is calculated is the property value as of December 31, 2017. The effect of this adjustment decreases net operating income by $1,598,000.

**Pro Forma IS/IT,** column (3.07), adjusts the actual level of information services and technology expense included in the 2016 test year to that expected during the rate period beginning May 1, 2018. This adjustment includes the incremental costs associated with software development, application licenses, maintenance fees, and technical support for a range of information services programs. These incremental expenditures are necessary to support Company cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer services. Company witness Mr. Kensok sponsors this adjustment and provides more information within his testimony. The effect of this adjustment decreases net operating income by $451,000.

**<u>Pro Forma Revenue Normalization</u>**, the final adjustment on page 7, column (3.08), adjusts January 2016 through December 2016 test period customers and usage for any known and measurable (pro forma) changes. In addition, the adjustment re-prices billed, unbilled, and weather adjusted usage at the base tariff rates approved for 2016, as if the January 11, 2016 base tariff rates were effective for the full 12-months of the test year. Ms. Knox is sponsoring this adjustment. The effect of this adjustment decreases net operating income by $3,286,000.

**Q. Please continue with your discussion of the Pro Forma adjustments included on page 8 of Exh. EMA-2.**

A. The first adjustment on page 8, **<u>Pro Forma Def. Debits, Credits and Regulatory Amortizations</u>,** column (3.09), adjusts certain items included in restating adjustment (1.02), which is included on an AMA 2016 commission basis level, to the level in effect for the rate period beginning May 1, 2018. Specifically, this adjustment revises the following deferred debit and credit deferral balances from AMA 2016 to AMA for the rate period (May 1, 2018 – April 30, 2019), consistent with prior Commission orders[18]: 1) Settlement Exchange Power; 2) CDA settlement Deferral; CDA/SRR (Spokane River Relicensing) CDR Deferral; 3) Spokane River Deferral; 4) Spokane River PM&E Deferral; and 5) Montana Riverbed Lease deferral. This adjustment also reduces amortization expense related to the expiration of the following regulatory amortizations: 1) Montana Lease Deferral; 2) 2012 Colstrip & Coyote Springs 2 Deferral; and 3) Spokane River Total Dissolved Gas Deferral. The effect of this adjustment reduces total rate base by $5,346,000 and increases net operating income by $1,013,000.

**Pro Forma 2017 Threshold Capital Additions,** column (3.10), reflects increases related to certain 2017 capital additions, together with associated A/D and ADFIT. This adjustment also includes associated depreciation expense for these 2017 additions. As sponsored and discussed by Company witness Ms. Schuh, based on Commission Order 05, the Company identified electric and natural Pro Forma capital projects that met the threshold of one-half of one percent of the Company's rate base (i.e., above $6.9 million for electric and $1.3 million for natural gas).[19] The effect of this adjustment increases rate base by $34,911,000 and decreases net operating income by $1,741,000.

**Pro Forma O&M Offsets,** column (3.11), as explained by Ms. Schuh, the Company reviewed large capital additions in 2017 to determine any offsets (e.g., reduced O&M costs, reduced load losses, etc.) resulting in rate period reductions effective May 1, 2018. Maintenance records were reviewed to determine whether any specific maintenance

[18] For a description of each deferral item, see discussion provided above for restating adjustment (1.02) Deferred Debits and Credits.
[19] Order 05, Docket Nos. UE-150204 and G-150205 (Consolidated), paragraph 39 and 40.

costs were incurred in the test period that would be reduced or eliminated by the investment for that capital project. Those reductions in costs were quantified and included as a reduction to O&M. The effect of this adjustment increases net operating income by $642,000.

**Pro Forma Director Fee Expense**, column (3.12), reflects an increase in director fee expense to reflect director fee expense using a 97% utility / 3% non-utility split.[20] Avista proposes to reflect director fee expense based on annual surveys of the Board of Directors of their time split between utility/non-utility operations, which reflect a 97% utility / 3% non-utility. This adjustment, as proposed by Avista, removes the effect of adjustment 2.12 (director fee expense noted above) reflecting a 50%/50% sharing, to reflect the proper level of director fee expense that should be included during the rate period. The effect of this adjustment decreases net operating income by $244,000.

**Q. As noted above, the Company is proposing to exclude 3% of Director Fee expenses, rather than 50%. What is the basis for removing 3% of these costs?**

A. Annually in November, the Company requests each of its Directors to estimate the time they spend on utility versus non-utility duties and responsibilities, based on their actual experience. The responses from the Directors in November 2016 indicated that 97% of the Directors' time is dedicated to utility matters, and approximately 3% to non-utility[21]. During the test period utilized in this case, the Company had recorded

[20] Restating adjustment 2.12 "Miscellaneous Restating Non-Utility /Non-Recurring Expenses," reduced director fee expense recorded on Avista's books at a 97% utility/3% non-utility basis, to a 50%/50% per Docket No. UE-090134. This adjustment, as proposed by Avista, removes the effect of adjustment 2.12 to reflect the proper level of director fee expense.

[21] A change from previous years, in which the results of the Board of Director surveys had been approximately 90% utility/10% non-utility, is directly reflective of the sale of Avista's subsidiary Ecova and the purchase

approximately 97% to utility and 3% to non-utility expense. Adjustment 2.12 (Miscellaneous Restating Non-Utility /Non-Recurring Expenses Adjustment), however, reduced this expense to a 50/50 sharing. The Company believes director fees are now understated, and that the survey results are a better indication of the proper costs to charge the utility based on the discussion below.

In Docket Nos. UE-090134 and UG-090135, Order No. 10, in reference to a 90/10 sharing for D&O insurance, the Commission stated:

> D&O insurance is a benefit that is part of the compensation package offered to attract and retain qualified officers and directors. Accordingly, it makes sense to split the costs in the same manner we require other elements of their compensation to be shared. Based on the formula currently used to allocate officer compensation between ratepayers and shareholders, this results in 90 percent of the costs being included for recovery in rates. (emphasis added) (See page 56, paragraph 137)

This Commission, as shown above, has recognized that D&O insurance is part of the "compensation package" (splitting such costs on a 90/10 basis[22]). Similarly, Directors' fees, like D&O insurance referred to above, are a part of the Directors' compensation package offered to attract and retain qualified Directors. Based on the actual time dedicated to the utility, a 97%/3% sharing should be applied to Directors' fees. Using a 97%/3% sharing for the Director fees paid during the test period for participating in Avista Corp./Utility board meetings, increased the Company's expense included in this filing by approximately $375,000. The net effect of this adjustment reduces net operating income by $244,000.

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of Alaska Energy and Resource Company (AERC) / Alaska Electric Light and Power Company (AEL&P) in mid-2014.

[22] Based on survey results of Avista Officers during each calendar year, D&O insurance is currently split approximately 90% utility / 10% non-utility.

**Pro Forma Normalize CS2/Colstrip Major Maintenance**, column (3.13), reflects an increase to the normalized major maintenance expense included above in restating adjustment (2.16), which reflected normalized CS2/Colstrip major maintenance for the 2016 historical test period. This adjustment reflects the normalized level of major maintenance related to the Company's Colstrip Units 3 & 4 facilities, expected during the rate period effective beginning May 1, 2018. Normalized major maintenance in this adjustment reflects 1/3 of the 2016 ($3.6 million) and expected 2017 ($3.5 million) Colstrip major maintenance overhauls, or $2.361 million, on a system basis. The results of this adjustment on a Washington share bases, increases normalized major maintenance expense by $347,000,[23] decreasing Washington net operating income by $226,000. [24]

**Pro Forma Underground Equipment Inspection**, the final adjustment on page 8, column (3.14), reflects underground equipment inspection expenses for Washington planned during the rate year. The Company has implemented a program intended to quickly and efficiently inspect and update safety/decal markings on Company Padmount Transformers in accordance with regulatory guidance provided by the State of Washington[25], National Electric Safety Code, and IEEE. This program will facilitate the systematic updating of safety decals related to transformer safety decal/marking for the safety of the general public and utility crews, prevention of unauthorized/unintentional

[23] System pro forma level $2.361 million (above) compared to $1.834 million (system restated level from adjustment 2.16), or $530,000 system adjustment.

[24] A normalized level of expense will occur for regulatory purposes, and for customers. However, for financial purposes and for shareholders, each of the two-years (in the three-year cycle) as actual major maintenance occurs, the Company will under-earn approximately 1/3 of the maintenance costs. Similarly, the Company will over earn in the one-year (in the three-year cycle) there is no maintenance by 1/3 of the maintenance cycle.

[25] WAC 296-24-95605, WAC 468-34-135 350, NESC C2-2007, and IEEE C57

access to energized components of the distribution system, clearance of padmounts overgrown with vegetation (for example) and provide direction for locating padmount equipment. The net impact of this adjustment is an increase of approximately $532,000 expense ($800,000 system) and decreases net operating income by $346,000.

**Q. Please describe the subtotal on page 8 "Non-Energy Pro Forma Subtotal."**

A. This column provides the sub-total of net operating income, total rate base, and overall revenue requirement of $20,892,000, related to non-energy pro forma costs. This column provides the pro forma sub-total prior to the final pro forma adjustment 4.00, which includes pro forma power supply costs as explained below.

**Q. Turning to page 9 of Exh. EMA-2, please explain the final pro forma adjustment 4.00.**

A. The final adjustment, **<u>Pro Forma Power Supply & Transmission Revenues (ERM Related Only),</u>** column (4.00), includes pro forma power supply related revenue and expenses to reflect the twelve-month period May 1, 2018 through April 30, 2019, using 2016 historical loads. Mr. Johnson's testimony outlines the system level of pro forma <u>power supply revenues and expenses</u> that are included in this adjustment. Mr. Schlect outlines the system level of pro forma <u>transmission revenues</u> that are included in this adjustment. This adjustment calculates the Washington jurisdictional share of those figures. The net effect of this adjustment decreases net operating income by $10,288,000.[26]

[26] As explained in Exh. EMA-1T, for Rate Year 1 (effective May 1, 2018), the increase in net power supply expenses increases the requested revenue requirement by $16.6 million, compared to that currently authorized (approximately 27% of the total electric Rate Year 1 request). Mr. Johnson discusses the changes in power supply costs in Rate Year 1, explaining that over $8 million is due to the expiration of the Portland General Electric (PGE) capacity sales contract in December 2016.

**Q. Please explain the final pro forma column "PF Ttl" on page 9 of Exh. EMA-2.**

A. The final pro forma column "PF-Ttl," titled **Pro Forma Including PS Total,** provides the total pro forma results, including power supply, of $37,501,000. This represents the overall revenue requirement shortfall per the electric Traditional Pro Forma Study[27], as previously showed on page 1 of Exh. EM-2.

**Q. What are the purpose of the last two columns shown on page 9 of Exh. EMA-2?**

A. The last two columns labeled "9/1/2017 Power Supply Update Tariff Schedule" and "Power Supply Incremental (Billed) Impact Increase/Decrease," are provided for informational purposes only. These columns are provided to show the effect of the expiration of Schedule 93 "Power Supply Update," filed coincident with this general rate case filing. As discussed by Company witness Mr. Ehrbar, the Company has filed, coincident with this general rate case, its Power Cost Rate Adjustment (PCRA) filing requesting an increase in revenues of $14.976 million[28] (or 2.9%) effective September 1, 2017, recovered through Tariff Schedule 93. The PCRA reflects changes in net power supply costs, including the expiration of the PGE capacity sales contract. Schedule 93 would expire, effective with the change in base rates from this general rate case, upon

[27] As noted in Exh. EMA-1T, the results of the Traditional Pro Forma Study will not yield the electric and natural gas revenue increases necessary for the prospective rate year. The Traditional Pro Forma Studies alone do not provide sufficient rate relief; thereby warranting the use or inclusion of other "tools" available to this Commission. Approval of other "tools," such as that proposed by Avista including EOP 2017 rate base and an adjusted capital structure, would allow the Company an opportunity to earn its authorized rate of return. The EOP Rate Base Studies represent the Company's requested rate relief in this proceeding and are provided as Exh. EMA-3 (electric) and Exh. EMA-7 (natural gas).

[28] As shown in column labeled "9/1/2017 Power Supply Update Tariff Schedule," on page 9 of Exh. EMA-2.

completion of this rate proceeding. If the September 1, 2017 proposed rate change reflecting increased power supply costs is approved, the incremental power supply cost increase to customers from this general rate case effective May 1, 2018 is $1.652 million (or 0.32%)[29].

[29] As shown in column labeled "Power Supply Incremental (Billed) Impact Increase," on page 9 of Exh. EMA-2.