# Appendix B.
# Detail on Electric Portfolio Screening Model

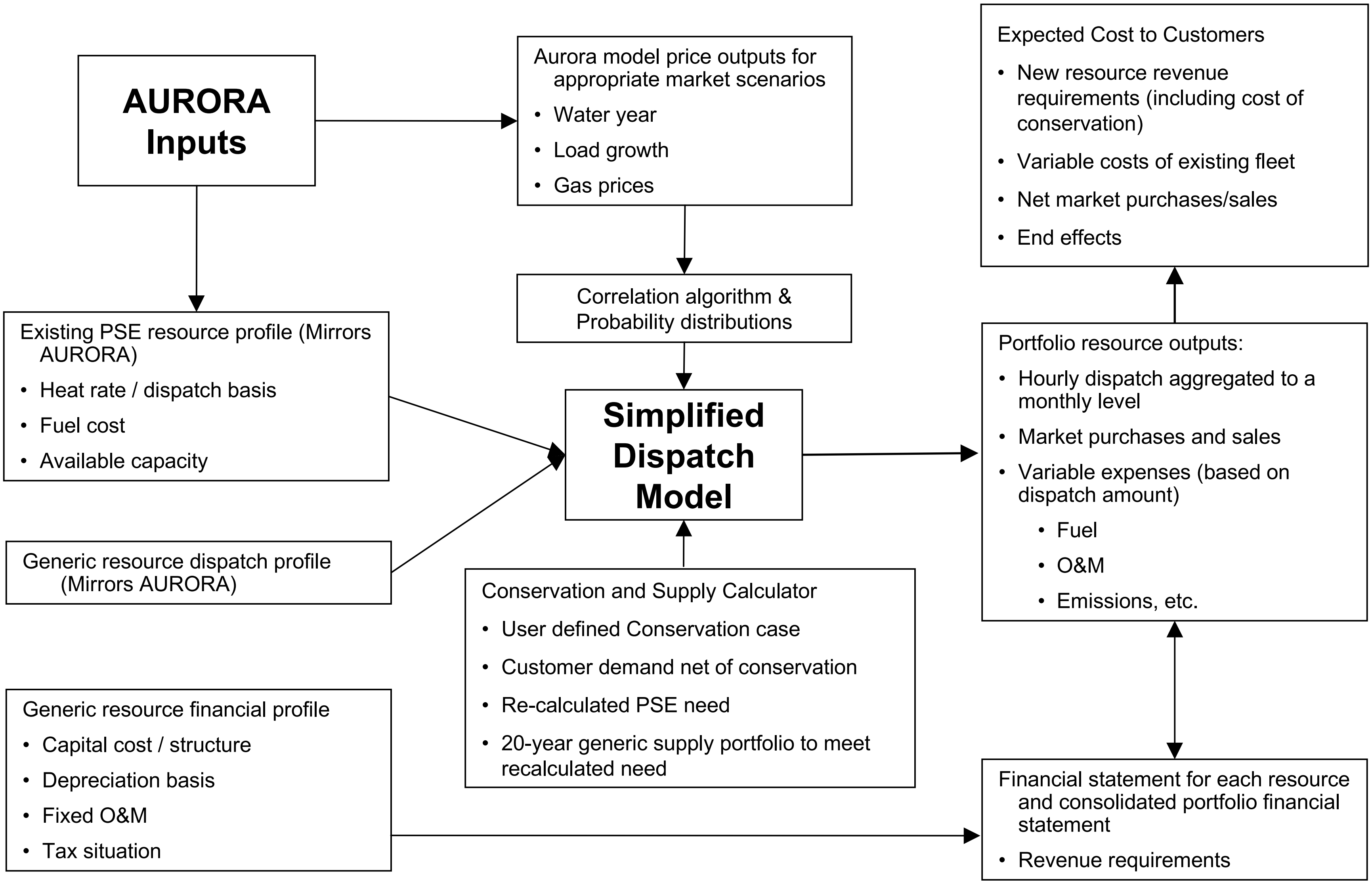
# Contents

- Portfolio Development
- Screening Model Logic
- Assumptions

# Portfolio Construction Assumptions and Considerations

- In the 04/30/03 LCP, the supply resource portfolios were constructed “by hand” using 25 MW increments, the supply resource portfolios are now automatically constructed to exactly match the need according to the following rules:
  - 10% of PSE’s demand will be met with renewable resources by 2013 and maintained thereafter (goal from the 04/30/03 LCP)
  - If there is no need in the months May thru August, then need from the remaining months will be met with Shaped CCGT MW
  - When need arises in the summer months, it will be met with a mix of thermal resources, 50% CCGT, and 50% coal
- Wind resources are added in a staggered fashion throughout the 10-year planning horizon and no wind is installed until 2005
- Whenever a CCGT resource is added (either full or shaped), an additional 13.5% of the CCGT capacity is added in the form of Duct Firing
  - PSE needs more capacity than energy
  - Duct Firing is significantly cheaper than SCGT
- Shaped CCGT rules:
  - PSE takes power from September to May
  - PSE would incur ~75%% of the capital cost on a monthly market price weighted basis
  - Only the CCGT (not the Duct Firing) is jointly owned
- SCGT Capacity is sold forward as follows:
  - PSE has rights to the capacity from Nov to April
  - 100% of the fixed costs plus return are recovered for the 6-month capacity sale from May to October

# Integrated LCP Screening Tool Modeling Process Flow Chart



# Integrated LCP Portfolio Screening Tool - Overview

**The Integrated Portfolio Screening Tool is composed of three main parts:**

- Conservation Load Impact and Supply Resource Calculator
  - Formerly the Portfolio Tester, now is integrated into the Screening Model calculations
  - The zero conservation total demand forecast is adjusted by the amount of conservation assumed in a conservation case and is used to re-calculate the PSE need for both energy and capacity
  - Supply resources are added automatically subject to user-defined rules to meet the remaining need

- Dispatch Model Calculation
  - Dispatches PSE fleet and potential new supply resources against hourly power prices from Aurora for WA/OR region
  - Utilizes the same inputs to Aurora for plant profiles and net demand
  - Output from dispatch model includes MWh for the PSE fleet and an assumed portfolio of new resources and their associated variable (or incremental) costs (fuel, O&M, etc.)

- Financial Summary and Expected Cost to Customer Calculation
  - MWhs produced and variable cost data from the dispatch model is used in conjunction with fixed cost assumptions to derive a ‘bottom up’ revenue requirement for each new resource being considered
  - A financial summary is generated for each new resource technology that includes an regulated income statement and an approximation of regulatory asset base
  - Financial data from each new resource is then consolidated
  - The comparative incremental cost (or going forward cost) to customers for a particular resource portfolio is developed by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases, and the revenue from market sales with the revenue requirements (including conservation expense) from the new resource portfolio over a 20 year period
  - The NPV of the 20 year strip of “forward” costs to customers is then calculated at the pre-tax WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

# Detailed View of the Conservation Impact and Supply Resource Calculation Process – Input Data

- Conservation load impact data in total MWh form as follows:
  - Eight residential bundles: Appliances, HVAC, Lighting, and Water heating for both new construction and existing construction
  - Eight commercial bundles: Appliances, HVAC, Lighting, and Water heating for both new construction and existing construction
  - One Industrial bundle
- The MWh of conservation were further broken down into price points, four for the residential and commercial bundles and one for industrial totaling 65 individual unique conservation bundle/price points
- The duration of benefit of each of the 65 conservation bundle/price points
- Weighted 8760 load shapes for the 17 bundles (8 residential, 8 commercial, and 1 industrial)
  - The load shapes were normalized such that the total annual MWh conservation impact could be multiplied by each hours value to yield the hourly conservation impact
  - The load shapes provided were based on shapes originally developed by NPPC

# Detailed View of the Conservation Impact and Supply Resource Calculation Process – Total Demand Adjustment and Supply Resource Calculation

- Conservation cases are user defined by selecting a mix of the 65 unique bundle/price points
- The MWh associated with the selected bundle/price points are rolled up to the bundle level and grossed up by 6.5% for line losses
- Each of the 17 bundles has an associated hourly load shape that has been normalized to allow the rolled up bundle annual MWh to be directly spread to hourly before they are consolidated into a total hourly conservation impact
  - The base load shapes provided were developed from the load shapes defined by NPPC
  - The load shapes are for a 2004 base year and are adjusted for the proper annual start date for the years 2005-2023
- The 20-year total hourly conservation impact is then subtracted from the 20-year no-conservation total demand forecast to develop the conservation adjusted total demand forecast
- The conservation adjusted hourly total demand forecast is rolled up to a monthly aMW level and used to recalculate the PSE energy need
- The capacity value of conservation is assumed to be the average of the maximum hour of conservation in December, January, and February and is used to adjust the capacity need
  - Assumes that the highest hour of conservation savings is coincident with the peak hour of load
- Supply portfolios are constructed based recalculated capacity and energy need

# Detailed View of the Conservation Impact and Supply Resource Calculation Process – Dispatch and Financial Impact of Conservation

- The 20-year total hourly conservation impact is subtracted net demand associated with the 20-year no-conservation total demand forecast
  - This process is mathematically equivalent to the treatment of the must-run resources (wind, NUG's, etc.) and the hydro resources
  - The net demand is the total demand minus current PSE contracts
- The calculated supply portfolios are dispatched against the June AURORA price forecast, hourly spot market purchase and sales are based on the total hourly dispatch of the PSE fleet (current and future generic) and the hourly conservation adjusted net demand
- The cost of the conservation bundles/price points assumed in the case flow directly to revenue requirement and are calculated as follows:
  - The cost of each conservation bundle/price point is spread over the respective useful life of the bundle/price point
  - For bundle/price points where the useful life is less than 20 years, we assume a 100% "re-up" rate for as many times as necessary to fill the 20 year period
  - There is no escalation of cost of bundle/price points when spread over the useful life or when re-upped
  - The total cost of the bundle/price points are reduced by 10% to reflect the environmental benefit of foregoing fossil supply additions through conservation
  - The total cost of conservation flows to revenue requirement with no return component
- End effects are dealt with in a similar fashion as the end effects of supply resources
  - A market benefit of the residual conservation from year 2024-2050 is calculated by subtracting the total cost of conservation from the market value of the conserved MWhs
  - This value is discounted back to year 1 and raises or lowers the revenue requirement based on the attractiveness of the conservation case

# Net Demand Development

- Monthly demand and resource summaries extracted from Aurora for the forecast period are used to develop Net Demand
- The monthly Net Demand is derived by taking the total demand and subtracting contract purchases/(sales)
- The monthly Net Demand is converted to hourly Net Demand through the following process:
  - AURORA adjusts the base load shape for the proper day on which 1/1/xxxx falls for the 20-year analysis period
  - Factors are developed based on this 20-year hourly load shape
  - These factors for each hour are then applied to the monthly Net Demand to create 8760 Net Demand profiles for the 20-year forecast period

# Dispatchable Resources

- The dispatchable plants are:
  - PSE owned: Fredonia1&2, Fredonia 3&4, Frederickson 1&2, Whitehorn 2&3, Colstrip 1&2, Colstrip 3&4 and Encogen (dispatchable)
  - NUG's: March Point 1&2 (dispatchable), Sumas, and Tenaska
  - New resources: CCGT (including structured deals), SCGT, and coal
- There are two primary data inputs to the dispatch logic from the dispatchable plants:
  - Dispatch Basis: This is the marginal cost of dispatch and is sum of variable O&M, fuel cost (calculated by running a "burner tip" $/MMBtu fuel cost through the plants heat rate to arrive at $/MWh), and any other incremental costs (e.g. emissions, transmission, etc.)
  - Dispatchable Capacity: The dispatchable capacity adjusts the net capacity for an asset by a forced outage rate applied evenly over all periods, and an planned outage rate applied when the outage is expected

| Plant | Net Capacity (MW) | Heat Rate (Btu/KWh) | Forced Outage Rate (%) | VOM ($/MWh) | Fuel Cost (Note/$/MMBtu) | Planned Outage Period (Approx.) |
|---|---|---|---|---|---|---|
| Fredonia 1&2 | 202.1 | 11,569 | 16.87 | 2.12 | Sumas + trans. | 1 week in May |
| Fredonia 3&4 | 108.0 | 10,540 | 5.00 | 2.12 | Sumas + trans. | 1 week in May |
| Frederickson 1&2 | 141.0 | 12,450 | 14.26 | 2.12 | Sumas + trans. | 1 week in April |
| Whitehorn 2&3 | 134.4 | 11,987 | 13.23 | 2.12 | Sumas + trans. | 1 week in April |
| Colstrip 1&2 | 298.6 | 10,889 | 10.38 | Inc. in fuel | 0.45 | 2 weeks in May |
| Colstrip 3&4 | 359.9 | 10,695 | 8.29 | Inc. in fuel | 0.60 | 2 weeks in June |
| Encogen - Disp. | 120.0 | 9,032 | 1.97 | Inc. in fuel | Sumas + trans. | Inc. in FOR |
| March Point 1 - Disp. | 0.0 | 8,500 | 0.20 | Inc. in fuel | Sumas | Inc. in FOR |
| March Point 2 - Disp. | 13.0 | 12,000 | 0.20 | Inc. in fuel | Sumas | Inc. in FOR |
| Sumas | 133.0 | 8,200 | 1.80 | Inc. in fuel | Sumas | Inc. in FOR |
| Tenaska | 245.0 | 8,700 | 0.30 | Inc. in fuel | Sumas | Inc. in FOR |
| CCGT - Generic | NA | 6,856 | 5.00 | 2.00 | Sumas | 1 week |
| SCGT - Generic | NA | 10,817 | 3.60 | 2.00 | Sumas | 1 week |
| Coal - Generic | NA | 8,922 | 7.00 | 2.00 | 0.73 | 2 weeks/yr |

**Source: 2002 Rate Case with some updates, Generic: EIA, NPPC**

# Must Run and Renewable Resources

- The must run plants are:
  - PSE Owned: All hydro plants, and Encogen MR
  - NUG's: March Point 1&2 MR
  - New resources: Wind
- The Must Run plants have only have Dispatchable Capacity as input to the dispatch logic
  - The must run portions of Encogen and March Point calculate the Dispatchable Capacity is the same fashion as the dispatchable portions of those plants
  - The wind units have their nominal capacity adjusted for monthly availability based on seasonal variations in wind patterns (the proxy is currently for wind located in the Basin & Range region of OR and ID)
  - The hydro unit Dispatchable Capacity is based on the monthly availability for the average water year in the 40-year hydro data set from NWPP and the hourly dispatch shape for a 2003 base year in Aurora
    - ✓ The hourly shape adjusts the monthly average is a similar fashion as the Net Demand

| Plant | Net Capacity (MW) | Heat Rate (Btu/KWh) | Forced Outage Rate (%) | VOM ($/MWh) | Fuel Cost (Note/$/MMBtu) | Planned Outage Period (Approx.) |
|---|---|---|---|---|---|---|
| Encogen - MR | 51.0 | 9,830 | 1.97 | Inc. in fuel | Sumas + trans. | Inc. in FOR |
| March Point 1 - MR | 85.0 | 8,500 | 0.20 | Inc. in fuel | Sumas | Inc. in FOR |
| March Point 2 - MR | 50.0 | 8,500 | 0.20 | Inc. in fuel | Sumas | Inc. in FOR |
| Wind | NA | NA | 72% | 1.00 | NA | NA |

**Source: 2002 Rate Case with some updates**

# Must Run and Renewable Resources Continued

| Month | Basin & Range | Cascades & Inland | Northern California | Northwest coast | Rockies & Plains | Southern California |
|---|---|---|---|---|---|---|
| January | 119% | 103% | 22% | 119% | 161% | 68% |
| February | 139% | 90% | 28% | 157% | 157% | 66% |
| March | 107% | 107% | 69% | 107% | 102% | 97% |
| April | 105% | 107% | 113% | 86% | 84% | 128% |
| May | 94% | 121% | 181% | 84% | 77% | 175% |
| June | 71% | 107% | 188% | 84% | 73% | 133% |
| July | 56% | 111% | 210% | 101% | 35% | 147% |
| August | 61% | 107% | 185% | 54% | 42% | 95% |
| September | 72% | 94% | 96% | 66% | 52% | 87% |
| October | 74% | 73% | 65% | 80% | 100% | 82% |
| November | 159% | 85% | 24% | 140% | 130% | 65% |
| December | 143% | 96% | 18% | 121% | 188% | 57% |
| FOR | 72% | 70% | 69% | 70% | 64% | 69% |

- We are currently using the Cascade & Inland profile in the calculations
  - Appears to be where the most promising near term projects are located

# Emissions Assumptions

| **Emission rate (T/GWh)** | SO2 | NOX | CO2 | Source |
|---|---|---|---|---|
| Fredonia 1&2 | - | 0.00002 | 582.00 | PSE |
| Frederickson 1&2 | 0.00080 | 0.03900 | 582.00 | NPPC Generic |
| Fredonia 3&4 | 0.00080 | 0.03900 | 582.00 | PSE |
| Whitehorn 2&3 | 0.000003 | 0.00002 | 582.00 | PSE |
| Colstrip 1&2 | 2.27613 | 2.09048 | 1,119.24 | EPA |
| Colstrip 3&4 | 0.50220 | 2.19521 | 1,097.69 | EPA |
| Encogen (Dispatchable) | 0.00200 | 0.03900 | 411.00 | NPPC Generic |
| March Point 1&2 (Dispatchable) | 0.00200 | 0.03900 | 411.00 | NPPC Generic |
| Sumas | 0.00200 | 0.03900 | 411.00 | NPPC Generic |
| Tenaska | 0.00200 | 0.03900 | 411.00 | NPPC Generic |
| CCGT (Generic) | 0.00200 | 0.03900 | 411.00 | NPPC Generic |
| SCGT (Generic) | 0.00080 | 0.05523 | 582.00 | NPPC Generic |
| Coal (Generic) | 0.38200 | 0.35000 | 1,012.00 | NPPC Generic |
| | | | | |
| Escalation | 2.50% | - | - | |
| Base Cost/Ton | 200.00 | - | - | |

# Dispatch Logic

- The hourly dispatch of the PSE fleet and the new resources considered in the planning portfolio is done on a month by month basis (this is due to size constraints within Excel)
- The dispatch logic is as follows:
  - For each hour, the Dispatch Basis for each dispatchable plant is compared to the market price for that hour, if the Dispatch Basis is less than the market price, then the plant generates its Dispatchable Capacity for that hour, else, it does not dispatch that hour
  - The total generation from the dispatchable plants is summed for each hour
  - The total generation from the must run plants is added to the total generation from the dispatchable plants
  - The grand total of plant generation (dispatchable and must run) is compared to the Net Demand for each hour, if the amount generated is less than the Net Demand, then that amount represents a market purchase, if the amount generated is greater than Net Demand, than that amount represents a market sale
  - For every hour where there is a market sale or purchase, the market price at that hour is used to calculate the financial impact of the purchase or sale
- The major simplification from the dispatch logic in Aurora is that there is no provision for unit minimum run times, ramp rates, minimum dispatch levels, etc.

# End Effects for Supply Resources in the Screening Model

- The issue of end effects arises because we have a 20 year evaluation period with for assets with a 30 year life, this is compounded by the fact that our portfolio planning horizon allows asset additions to occur through year 10, effectively creating a 40 year horizon for asset life
- To deal with years 21-40 in the analysis, we use the following methodology:
  - Forecast the free cash flows (100% equity basis) from the assets for years 21 to 40
  - NPV the free cash flows to year 20 at the after-tax WACC
  - Compare the NPV at year 20 to the remaining book value at year 20
  - NPV the difference to year one at the after tax WACC
  - Subtract the year one value from the Total Cost to Customer
- The free cash flow are estimated using the following assumptions:
  - Revenue:  The revenue from year 17-20 is averaged and escalated at 2.5%
  - Fuel and VOM:  The fuel and VOM from year 17-20 is averaged and escalated at 2.5%
  - Capacity Factor:  The capacity factor from year 17-20 is averaged and held constant for year 21-40
  - FOM:  The FOM continues to be escalated as in years 1-20
  - Property Tax:  The property tax is trended down from year 17-20 (follows the trend down in rate base)
  - Insurance: The insurance is trended down from year 17-20 (follows the trend down in rate base)
  - Depreciation:  The tax depreciation is run out normally for all assets past year 20
- The impact of the end effects are relatively small in comparison to the Total Cost to Customer, on the order of 2-5% of the total depending on portfolio mix and planning level

# Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies*

- Dates used for analysis period
  - Planning horizon for resource acquisition is 20 years beginning Jan. 1, 2004
  - Model assumes 'financial close' date of 12/31/xxxx as for all generic resources
  - Analysis period is 20 years

- Expense / Capital escalation rates
  - Both fixed and variable O&M currently assume a 2 ½% annual escalation factor
  - Both periodic and acquisition capex assume a 2 ½% annual escalation factor
    - ✓ Methodology – The model assumes two kinds of additional capex: 'incremental capex' and 'acquisition capex.' 'Incremental capex' are capital expenditures (plant) acquired on an annual basis using a $/Kwh valuation. The current model assumes that 'incremental capex' is funded through available cash rather than by debt. Alternatively, the model assumes that 'acquisition capex', or capital expenditures related to acquiring new generation MW during the 10 year planning horizon, are financed using the debt to equity ratio supplied by PSE (60% debt to 40% equity).

- Capital Costs (New Acquisition Capex in $/kw)

| | All in Cost ($/kw) |
|---|---|
| CCGT | $710 |
| SCGT | $441 |
| Coal | $1,500 |
| Wind | $1,003 |
| Duct Fired | $150 |
| Shaped CCGT | $526 |

# Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies - continued*

- O&M Costs (Table below outlining Fixed rates in $/kw-yr and Variable O&M rates in $/MWh)

| | CCGT | SCGT | Coal | Wind | Duct Fired | Shaped CCGT |
|---|---|---|---|---|---|---|
| **Fixed Expenses ($/kW-year)** | | | | | | |
| FOM | 11.00 | 3.00 | 20.00 | 26.10 | - | 8.14 |
| Gas Transport | 15.55 | 15.74 | - | - | 15.55 | 11.51 |
| Electric Transmission | 14.88 | - | 29.76 | 14.88 | 2.48 | 11.02 |
| *Total* | 41.43 | 18.74 | 49.76 | 40.98 | 18.03 | 30.67 |
| **Variable Expenses ($/MWh)** | | | | | | |
| VOM | 2.00 | 2.00 | 2.00 | 1.00 | 2.00 | 2.00 |
| Fuel Basis Differential | 1.24 | 1.29 | - | - | 1.00 | 1.24 |
| *Total* | 3.24 | 3.29 | 2.00 | 1.00 | 3.00 | 3.24 |

- Finance and Regulatory assumptions
  - Cost of equity and debt (used for both the WACC and debt amortization calculations) – 11.0% and 7.24% respectively
  - Pre / After Tax WACC – 8.95% and 7.61% respectively
  - Conversion Factor (gross-up factor used in revenue requirement calculation) – 62.02%
    - ✓ Roughly equivalent to (1- Federal tax rate and miscellaneous regulatory fees)

- Heat Rate and Forced Outage Rates

| | CCGT | SCGT | Coal | Wind | Duct Fired | Shaped CCGT |
|---|---|---|---|---|---|---|
| Heat Rates | 6,856 | 10,817 | 8,922 | | 9,100 | 6,856 |
| Forced Outage Rates | 5% | 3.6% | 7% | 70% | 0% | 5% |

# Financial Summary and Revenue Requirement Calculation - *Calculation Detail*

**The revenue requirement for a specified portfolio utilizes a 'bottom-up' approach where total fixed and variable costs are used to back solve for the appropriate revenue stream that would yield an operating income stream sufficient to provide a desired regulated rate of return. The following discussion outlines how individual components of fixed and variable expenses are calculated:**

- Variable Costs – Fuel and Variable O&M
  - Fuel expense is calculated by multiplying the calculated number of MWh dispatched or generated each month, times the heat rate of the plant times the appropriate fuel curve (i.e. gas or coal)
  - Variable O&M is calculated by taking the appropriate VOM factor (as provided by PSE and illustrated on the previous slide), applying the VOM escalation percentage adjusted for time, and multiplying the resulting inflation adjusted VOM factor (in $/Kwh) times the number of Kwh produced for the selected technology
- Fixed Costs – Fixed O&M
  - The FOM Factor provided by PSE should includes all categories of fixed costs associated with the various technologies under consideration
  - The fixed cost calculation is similar to that of Variable O&M in that the FOM factor (quoted in $/Kw) provided by PSE is inflation adjusted using the escalation factor illustrated on the previous slide and multiplied times the plant capacity (rather than the number of Kwh produced)
- Depreciation - Book and Tax
  - Book – Modeled value assumes 30 year recovery on all capital additions (Wind 20 years)
  - Tax – The portfolio model contains flexibility to select from 5, 10, 15 and 20 year MACRS (half-year convention)
    - ✓ The current test cases utilize 5 year MACRS for 'green' resources, 15 year MACRS for simple and combined cycle gas and 20 year MACRS for coal fired resources.

# Financial Summary and Revenue Requirement Calculation - *Calculation Detail - continued*

- Debt Service – Interest
  - The interest is calculated as a function of Rate Base
  - The long-term capital structure assumes 52.57% debt
  - The interest rate is assumed to be 7.4%

- Tax – Current and Deferred
  - Current taxes are computed on taxable income calculated using tax depreciation rates previously discussed
  - Differences between book and tax depreciation are the only items considered to generate book/tax differences that give rise to deferred taxes.
  - Currently, the model assumes a 35% effective marginal rate

# Financial Summary and Revenue Requirement Calculation - *Expected Cost to Customer*

- Expected Cost to Customer is the point at which various alternative portfolios will be measured
- Expected Cost to Customer in the portfolio model is calculated as follows:
  - The comparative incremental cost to customers for a particular resource portfolio is developed by combining:
    - ✓ The variable cost of dispatch from the existing dispatchable PSE fleet
    - ✓ The variable emission cost from the existing PSE fleet
    - ✓ The cost of market purchases
    - ✓ The revenue from market sales
    - ✓ The revenue requirements from the new resource portfolio over a 20 year period including the variable expense associated with market sales and the costs associated with conservation
  - The NPV of the 20 year strip of incremental costs to customers is then calculated at the pre-tax WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only