APPENDIX C
ELECTRIC MODELS

PSE uses three primary models for least cost planning. The AURORA model analyzes the western power market to produce hourly electricity price forecasts. The Portfolio Screening Model (PSM) tests portfolios to evaluate PSE's long-term incremental portfolio costs. Finally, the Conservation Screening Model (CSM) tests demand-side resource cases to determine the most cost effective level for a given generation portfolio.

The first section of this appendix discusses the AURORA model's algorithm along with key inputs used. The AUIRORA section ends with tables of monthly power prices for the scenarios used. The second section discusses the Portfolio Screening Model (PSM) and the Conservation Screening Model (CSM), and provides key input information. The results from PSM and CSM are detailed in Chapter X and Appendix G.

THE AURORA DISPATCH MODEL

A. Overview

PSE uses the AURORA model to estimate the market price of power used in serving its core customer load. The model is described below in general terms to explain how it operates, with further discussion of significant inputs and assumptions. [The following text was provided by EPIS, Inc. and edited by PSE.]

AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources, regional demand for power, and transmission, which drive the electric energy market. AURORA models the competitive electric market, using the following modeling logic and approach to simulate the markets: prices are determined from the clearing price of marginal resources. Marginal resources are determined by "dispatching" all of the resources in the system to meet loads in a least cost manner subject to transmission constraints. This process occurs for each hour that resources are dispatched. Resulting monthly or annual hourly prices are derived from that hourly dispatch.

AURORA uses information to build an economic dispatch of generating resources for the market. Units are dispatched according to variable cost, subject to non-cycling and minimum-run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

B. Inputs

Numerous assumptions are made to establish the parameters that define the optimization process. The first parameter is the geographic size of the market. In reality, the continental United States is divided into three regions, and electricity is not traded between these regions. The western-most region, called the Western Electricity Coordinating Council (WECC) includes the states of Washington, Oregon, California, Nevada, Arizona, Utah, Idaho, Wyoming, Colorado, and most of New Mexico and Montana. The WECC also includes British Columbia and Alberta, Canada, and the northern part of Baja California, Mexico. Electric energy is traded and transported to and from these foreign areas, but is not traded with Texas, for example.

For modeling purposes, the WECC is divided into 21 areas primarily by state and province, except for California which has eight areas, Nevada which has two areas, and Oregon and Washington which are combined. These areas approximate the actual economic areas in terms of market activity and transmission. The databases are organized by these areas and the economics of each area is determined uniquely.

Load forecasts are created for each area. The load forecast includes the base year load forecast and an annual average growth rate. Since the demand for electricity changes both over the year and during the day, monthly load shape factors and hourly load shape factors are included as well. All of these inputs vary by area: for example, the monthly load shape would show that California has a summer peak demand and the Northwest has a winter peak. PSE adopted the long-run forecast from EPIS after reviewing and comparing the forecast with the U.S. Energy Information Agency (EIA) and the Northwest Power and Conservation Council (NPCC). The EPIS and NPCC forecasts were very close, and EPIS relied on EIA and North American Electric Reliability Council (NERC).

Exhibit C-1
Regional Growth Rates

Regions (States)	Annual Average Growth Rate
Rockies (WY, MT, CO, ID)	2.0%
Northwest (WA, OR, BC, NV-No.)	1.8%
California	1.97%
Southwest (AZ, NM, NV-So.)	2.5%
Utah	1.8%

All generating resources are included in the resource database. Information on each resource includes its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). Previously, the generating resource landscape saw few changes; however, numerous plants are under construction, and many more are in the planning stage. PSE uses current knowledge of Northwest resources, and utilizes EPIS, Henwood, public sources (e.g., Cal-ISO, CEC, etc.) and private contacts to update the over 3,000 electric power resources in the West.

The model incorporates resources that are under construction with expected online dates; however, because of numerous factors causing uncertainty, PSE includes only new plants fueled by natural gas that will be completed in 2005. Coal plants currently under construction with online dates through 2006 were also included, as well as two wind plant projects in which PSE is directly participating.

Exhibit C-2
Power Plants under Construction

Plant	Location	Fuel	Capacity (MW)	Online Date
Genesee	AB	Coal	440	1/1/2005
Montana First	MT	Gas	240	1/1/2005
Pastoria Energy Center	CA	Gas	750	6/1/2005
Metcalf Energy Center	CA	Gas	600	6/1/2005
Cosumnes Power Plant	CA	Gas	500	6/1/2005
Rocky Mt. Power	MT	Coal	116	12/1/2005
Hopkins Ridge	WA	Wind	149.4	1/1/2006
Springerville	AZ	Coal	400	6/30/2006
Wild Horse	WA	Wind	239.4	1/1/2007

Many states in the WECC have passed statutes requiring renewable portfolio standards (RPS) to support the development of renewable resources. Typically an RPS states that a specific percentage of energy consumed must be from renewable resources by a certain date (e.g., 10 percent by 2015). While these states have shown clear intent for policy to support renewable energy development, they also provide pathways to avoid these strict requirements. CERA, as part of its Rearview Mirror scenario, assumes that the laws will be relaxed after 2010. Exhibit C-3 shows the scope and timing of the various RPS in the WECC.

Exhibit C-3
State Renewable Energy Portfolios

State	Percent Renewable Energy	Effective Date
CA	20	2017
AZ	1.1	2007
NM	10	2011
NV	15	2013
CO	10	2015
OR/WA	10	2013

For the Green World scenario, PSE included all necessary resources so that all states would meet the guidelines. For the Business as Usual scenario, renewable resources are built until 2011 and the market may build more after that. The Current Momentum scenario follows the Business as Usual, with the addition of a standard for OR and WA.

The price of fuel is an important factor in determining the economics of electric power production. The two most important fuels are natural gas and coal. The fuels need to be priced appropriately for each area. For example, a plant in Washington may receive its gas from Canada at the Sumas hub, whereas a plant in Southern California may receive gas from New Mexico or Texas at the Topock hub, which is priced differently. PSE adopted the CERA Rearview Mirror forecast as its base forecast in 2004. In addition to the Rearview Mirror forecast, PSE also uses the CERA Green World forecast and the CERA World in Turmoil forecast for other scenarios.

Coal prices were adopted from the EIA 2004 Annual Energy Outlook. They provide long-run prices for three coal basins: Southwest (NM and AZ), Rockies (CO and UT) and Powder River Basin (MT and WY). They also provide information on costs associated with transporting the coal to other areas, which is added into the fuel cost for resources for the different areas.

Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydro power generation is based on the average stream flows for the 60 historical years of 1929-1988. While there is also much hydro power produced in California and the Southwest (e.g., Hoover Dam), it does not drive the prices in those areas as it does in the Northwest. In those areas the normal expected rainfall and hence the average power production is assumed for the model. For sensitivity analysis, PSE can vary the hydro power availability, or combine a past year's water flow to a future year's needs.

Electric power is transported between areas on high voltage transmission lines. When the price in one area is higher than it is in another, electricity will flow from the low priced market to the high priced market (up to the maximum capacity of the transmission system) which will move the prices closer together. The model takes into account two important factors that contribute to the price: first, there is a cost to transport energy from one area to another, which limits how much energy is moved; and second, there are physical constraints on how much energy can be shipped between areas. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas. EPIS updates the model to include known upgrades (e.g., Path 15 in California) but the model does not add new transmission "as needed." Transmission analysis for the May, 2005 Least Cost Plan was done outside the AURORA model.

C. Long Run Optimization

AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

Exhibit C-4 shows the cost and performance characteristics for the generic resources in AURORA. The primary source of information is the EIA, "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies." The costs were adjusted to $2,000, which is necessary for input to AURORA.

Exhibit C-4
Cost and Performance Characteristics

Technology	Capacity (MW)	Heat Rate (btu/kWh)	All-In-Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
CCCT	400	6928	602	40.55	1.97
SCCT	188	9,545	399	24.84	3.90
Scrubbed Coal	600	9,000	1,112	39.00	2.95
Coal with CO2 Mitigation	380	9600	1,987	54.00	2.41
Wind	100		1,084	38.44	2.95

Costs in $2000 for AURORA modeling
Fixed O&M includes fixed power transmission and fixed gas charge for CCCT

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years. Exhibit C-5 is a series of tables with the AURORA price forecasts for the different scenarios.

Exhibit C-5
Monthly Flat Mid-C Prices
(Nominal $/MWH)

Business as Usual (BAU)

Business As Usual													
FLAT	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Ave**
2006	53.73	41.33	46.03	37.42	33.08	28.01	34.00	41.60	43.31	44.67	47.94	48.75	41.69
2007	48.79	41.32	42.45	38.84	34.27	29.08	35.92	45.49	49.00	47.28	46.97	46.62	42.19
2008	46.61	37.10	40.26	34.44	31.37	28.42	34.47	42.22	44.35	43.15	41.33	40.45	38.71
2009	37.69	33.32	36.27	30.73	27.80	23.07	29.10	36.31	39.75	38.60	37.00	36.02	33.82
2010	35.85	29.39	31.69	27.10	24.73	20.88	26.06	31.89	35.09	33.74	37.95	37.96	31.05
2011	36.89	34.12	36.88	31.10	27.50	22.95	30.98	38.62	42.82	39.99	41.56	41.37	35.42
2012	41.73	36.38	38.81	32.50	29.51	25.02	33.52	42.66	51.26	42.53	45.82	46.43	38.87
2013	44.91	40.93	43.35	36.04	31.51	26.33	37.02	46.73	59.18	47.48	51.65	51.95	43.10
2014	48.40	44.59	47.75	38.27	33.16	25.88	37.46	48.64	68.78	51.86	55.51	55.14	46.29
2015	54.22	46.43	49.66	40.56	35.35	28.48	41.28	52.81	73.23	53.88	54.61	52.47	48.59
2016	51.30	39.28	43.11	35.61	32.31	27.73	36.21	48.70	74.09	49.16	48.44	48.34	44.55
2017	46.64	42.09	42.99	36.70	34.21	29.79	38.98	51.99	73.43	52.40	51.73	51.21	46.02
2018	49.97	45.68	48.37	42.18	38.56	33.42	44.68	57.74	78.00	55.74	56.35	56.56	50.62
2019	54.47	49.55	52.36	45.24	40.57	30.70	43.89	55.86	71.99	57.30	60.44	60.69	51.94
2020	56.89	51.68	56.21	46.23	40.12	28.97	40.60	52.47	64.36	59.30	58.04	59.11	51.18
2021	58.13	53.46	57.12	48.32	41.91	31.06	42.78	55.50	74.43	61.33	61.66	61.63	53.95
2022	59.57	54.49	58.90	49.64	44.35	33.07	44.42	58.73	75.90	61.99	62.24	63.19	55.55
2023	62.50	56.91	60.73	53.46	49.70	37.10	49.55	64.99	81.74	63.75	64.76	65.27	59.22
2024	66.21	66.96	64.36	54.82	50.71	38.52	51.96	68.46	86.85	67.19	67.74	66.65	62.51
2025	66.16	64.21	65.98	60.86	52.20	42.19	56.45	77.82	90.52	70.13	70.51	69.03	65.51

Current Momentum (CM)

Current Momentum													
FLAT	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Ave**
2006	53.25	41.24	45.96	37.09	33.03	27.56	34.04	41.51	43.20	44.72	47.69	48.65	41.50
2007	48.41	40.95	42.09	38.13	33.73	27.17	34.66	44.32	48.31	46.45	46.38	45.94	41.38
2008	45.79	36.18	39.68	33.84	30.12	27.42	33.29	41.22	43.45	42.39	40.56	40.05	37.83
2009	37.27	32.75	35.78	30.50	27.19	22.01	28.15	35.33	39.07	38.15	36.70	35.64	33.21
2010	38.28	31.94	33.96	29.76	27.83	24.83	28.75	34.23	37.70	36.72	40.17	39.95	33.68
2011	38.64	36.02	39.01	33.44	30.14	26.01	32.31	39.20	43.82	42.35	43.48	42.85	37.27
2012	42.32	37.41	40.70	34.20	31.57	26.97	34.14	41.31	47.28	44.39	47.02	47.65	39.58
2013	44.75	42.01	45.17	37.72	33.10	27.09	36.30	44.68	54.30	48.58	51.98	52.08	43.15
2014	50.09	46.68	49.66	41.08	35.87	29.12	39.81	49.74	61.46	52.95	56.44	56.06	47.41
2015	55.67	48.50	51.77	43.13	38.71	31.80	42.31	53.57	71.88	55.94	55.89	54.28	50.29
2016	53.56	42.28	45.70	38.68	36.12	31.88	38.67	48.71	73.38	50.74	50.20	50.66	46.71
2017	50.39	45.58	46.53	40.29	37.81	33.75	41.71	57.16	81.27	55.83	55.12	55.51	50.08
2018	52.96	47.99	51.00	44.69	40.96	34.19	44.98	57.56	85.49	59.86	59.89	60.26	53.32
2019	56.79	51.61	55.76	46.13	40.77	32.73	43.28	54.38	80.04	60.49	62.03	63.76	53.98
2020	62.27	55.44	59.58	49.29	43.55	34.45	46.54	59.19	80.27	63.67	62.51	63.27	56.67
2021	60.80	55.50	59.27	50.29	44.66	36.00	47.21	59.87	81.34	63.71	63.16	64.45	57.19
2022	63.52	58.68	61.52	52.78	48.55	39.22	51.18	65.00	85.75	66.78	66.02	66.40	60.45
2023	64.74	60.03	63.00	54.79	51.42	40.98	52.37	66.76	89.56	68.09	66.78	68.04	62.21
2024	64.65	58.66	64.59	55.72	50.27	40.42	52.64	65.16	85.93	67.86	68.31	68.44	61.89
2025	66.82	61.11	66.20	57.09	52.96	42.85	54.70	68.05	87.27	69.55	69.08	70.38	63.84

Green World (GW)

Green World													
FLAT	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Ave**
2006	52.12	39.84	45.03	36.27	32.18	25.08	32.43	40.71	42.59	44.06	46.63	48.74	40.47
2007	47.57	40.84	42.13	37.74	33.00	24.46	32.90	43.17	46.65	45.42	45.95	45.69	40.46
2008	44.60	35.41	39.24	33.58	29.31	25.08	31.32	40.44	43.15	41.55	45.15	44.33	37.76
2009	40.13	35.71	40.18	33.65	30.31	22.98	30.67	40.13	44.34	43.41	45.18	45.03	37.64
2010	45.99	42.86	48.65	43.84	38.16	30.55	40.44	51.32	57.09	54.79	55.50	54.95	47.01
2011	52.04	48.46	55.29	46.48	41.61	31.73	43.07	55.22	61.24	58.80	57.92	51.65	50.29
2012	51.46	47.16	52.35	44.13	40.50	33.77	43.22	53.79	58.83	55.86	55.63	55.47	49.35
2013	53.94	48.98	53.33	45.28	41.55	34.53	44.19	54.60	61.51	57.42	57.74	57.41	50.87
2014	57.59	52.71	57.19	48.94	44.75	37.52	47.96	60.50	68.89	61.70	61.71	61.97	55.12
2015	59.99	54.86	58.94	51.10	47.14	40.96	50.71	62.52	72.50	63.48	62.42	61.22	57.15
2016	60.99	54.93	59.15	52.02	48.34	42.45	53.28	65.62	81.89	66.87	65.09	66.78	59.78
2017	62.25	55.98	61.50	53.50	49.90	42.44	52.93	65.67	78.01	67.98	67.70	68.65	60.54
2018	64.99	58.77	64.56	56.11	51.36	42.00	54.47	67.95	82.26	70.90	68.34	68.91	62.55
2019	67.94	59.79	64.41	55.15	51.04	42.28	54.21	68.12	83.54	70.64	69.46	71.22	63.15
2020	71.94	64.17	71.17	61.01	56.57	48.41	60.01	73.36	85.93	75.67	70.70	70.71	67.47
2021	73.81	65.14	71.01	61.56	58.18	50.66	62.23	76.17	90.48	75.93	73.15	73.70	69.34
2022	74.73	66.18	72.36	62.21	59.90	53.71	65.45	81.24	94.67	77.58	74.13	74.00	71.35
2023	76.95	68.22	73.96	64.60	63.29	57.25	70.03	90.70	100.66	81.03	76.48	76.50	74.97
2024	78.36	69.49	76.39	65.40	65.03	59.97	73.29	98.27	105.07	82.73	77.73	78.09	77.49
2025	80.19	71.26	78.01	67.60	67.43	62.60	75.16	105.27	105.93	83.72	78.80	79.23	79.60

Low Growth (LG)

Low Growth													
FLAT	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2006	53.12	41.13	45.68	37.29	32.74	27.62	33.74	41.51	43.11	44.66	47.50	48.63	41.40
2007	48.00	39.71	43.70	37.52	33.05	27.31	35.00	44.46	47.51	46.47	46.61	45.29	41.22
2008	46.03	34.21	37.54	32.46	29.12	25.78	31.64	39.29	41.39	40.41	38.69	37.60	36.18
2009	37.21	29.19	31.72	27.49	25.51	22.74	26.93	32.61	34.57	33.79	33.79	32.94	30.71
2010	33.31	30.20	32.63	28.27	26.10	23.44	27.52	33.52	35.40	34.40	34.90	34.45	31.18
2011	33.10	30.66	33.80	28.44	26.26	22.64	27.63	34.29	37.33	35.68	35.88	35.94	31.80
2012	35.90	32.27	35.54	29.93	27.73	23.84	29.59	37.21	45.95	37.78	40.32	40.47	34.71
2013	39.60	36.36	39.77	33.37	30.84	25.71	32.40	41.51	56.28	42.31	44.08	44.29	38.88
2014	42.51	38.98	42.54	34.75	31.62	26.16	34.40	43.74	57.91	45.06	46.64	46.63	40.91
2015	46.22	41.42	45.13	37.14	33.47	28.65	36.81	48.13	63.81	48.29	47.48	45.60	43.51
2016	45.65	40.44	43.84	37.46	34.70	31.11	38.92	53.53	71.64	49.85	48.64	48.04	45.32
2017	48.51	43.74	47.15	40.61	38.04	34.54	43.19	63.80	87.76	54.94	51.26	50.52	50.34
2018	48.72	42.81	46.66	39.95	37.19	33.16	41.49	56.64	81.71	52.40	48.71	47.79	48.10
2019	47.29	41.53	44.64	38.30	36.14	33.57	41.13	61.04	81.34	51.72	50.22	50.15	48.09
2020	49.88	44.69	49.36	42.41	39.87	35.69	45.05	65.83	82.77	56.35	48.09	46.94	50.58
2021	49.07	43.96	48.13	41.06	39.06	35.51	44.27	66.15	82.17	55.79	49.61	49.09	50.32
2022	49.74	45.49	49.57	41.98	40.55	37.79	46.47	77.16	80.71	57.09	50.53	49.74	52.24
2023	50.50	46.56	50.38	43.48	41.30	39.05	48.29	77.76	84.26	56.91	51.43	50.62	53.38
2024	50.47	45.83	50.99	43.74	41.70	37.30	46.09	77.50	83.73	58.99	51.30	50.61	53.19
2025	51.11	46.36	51.41	43.67	41.87	35.63	44.29	68.78	84.76	58.00	51.79	51.29	52.41

Robust Growth (RG)

Robust Growth													
FLAT	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2006	54.16	42.09	46.38	37.93	33.25	28.50	34.57	42.09	43.78	45.14	48.11	49.36	42.11
2007	49.87	42.27	43.36	39.76	34.73	29.99	36.91	46.62	49.98	47.92	47.57	47.27	43.02
2008	47.65	37.84	41.13	35.30	31.99	29.50	35.86	43.50	45.43	44.20	42.20	41.52	39.68
2009	39.35	34.53	37.60	31.78	29.11	24.78	30.57	38.44	41.60	39.89	38.20	37.42	35.27
2010	38.36	30.66	33.25	28.21	26.14	22.46	27.64	34.43	39.06	35.30	39.64	39.92	32.92
2011	39.98	36.14	39.13	32.83	29.94	26.10	33.74	42.67	51.72	42.67	43.61	43.61	38.51
2012	43.19	37.09	39.66	33.23	30.62	26.63	35.14	44.16	60.62	44.05	47.12	47.75	40.77
2013	42.53	39.22	42.63	34.79	30.78	23.17	32.63	41.26	54.23	45.92	49.01	49.60	40.48
2014	48.63	43.86	47.55	38.27	32.52	24.21	34.00	45.02	62.55	51.54	54.35	55.00	44.79
2015	54.76	46.42	49.63	41.07	36.36	27.89	38.20	51.36	71.35	53.22	53.62	52.13	48.00
2016	51.33	39.23	42.73	35.55	32.83	27.60	35.32	45.78	65.91	48.11	47.11	47.03	43.21
2017	47.36	43.16	43.35	37.54	35.07	31.18	39.86	56.78	76.13	53.18	51.85	51.74	47.27
2018	50.42	46.33	48.47	42.93	39.11	32.34	42.64	54.59	74.36	55.98	56.15	56.27	49.97
2019	54.57	49.18	53.41	44.64	39.55	28.81	39.36	50.69	70.68	58.38	59.07	60.24	50.72
2020	61.01	54.90	58.56	50.10	43.98	31.83	43.73	56.29	72.86	62.09	60.45	61.18	54.75
2021	60.43	57.32	59.02	52.23	47.92	36.45	48.81	63.17	76.77	63.21	62.63	63.33	57.61
2022	62.79	59.08	62.48	55.25	50.58	42.48	55.41	76.86	84.71	67.22	65.80	65.14	62.32
2023	63.82	63.25	64.48	58.54	55.19	45.29	57.18	77.75	87.28	67.21	66.57	66.46	64.42
2024	65.73	66.86	66.09	60.30	55.62	49.96	63.31	93.29	91.03	71.75	67.72	68.27	68.33
2025	68.30	65.32	70.30	62.39	58.47	52.76	68.83	102.96	96.00	73.45	70.58	71.15	71.71

Detail on Electric Screening Models

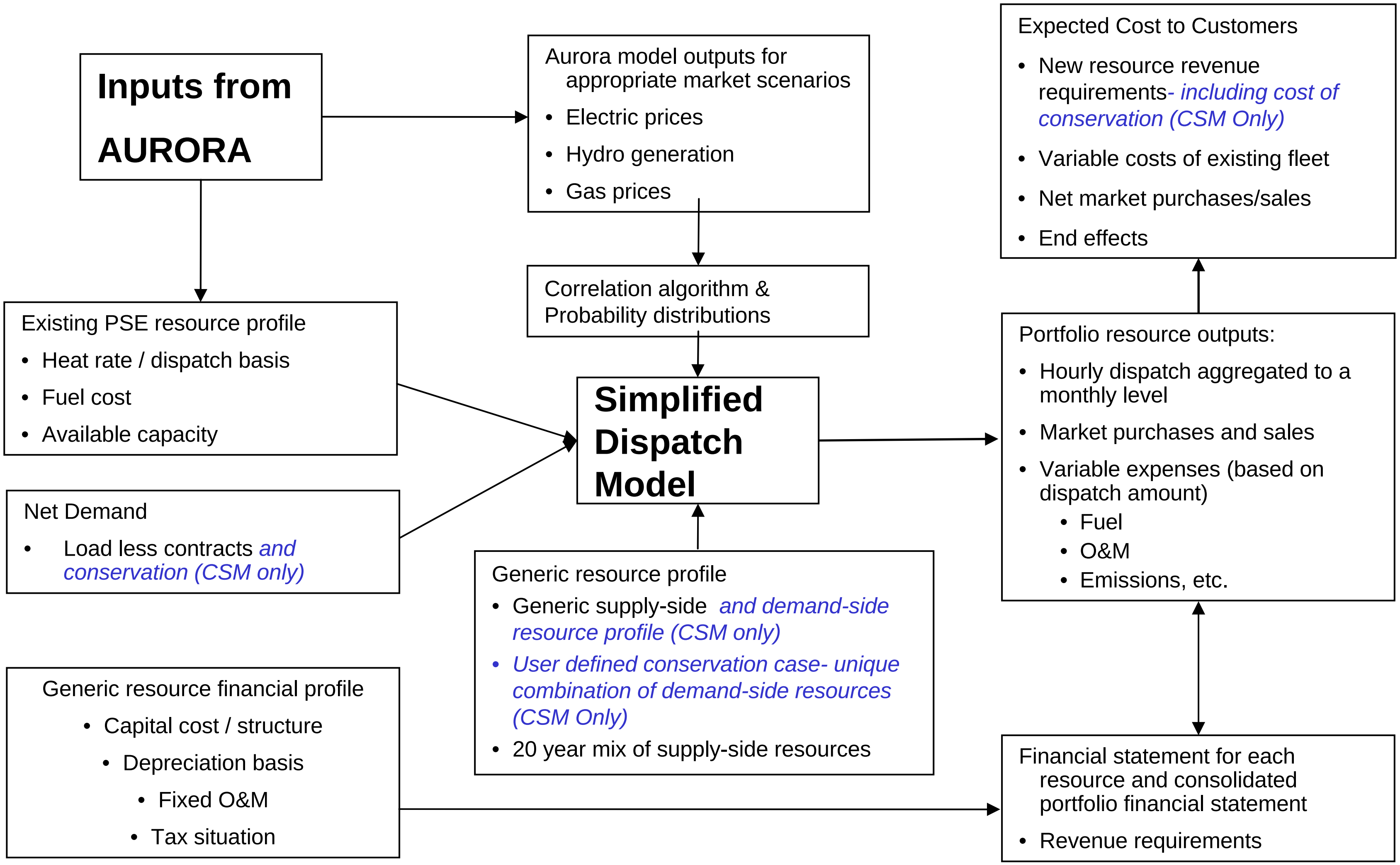
LCP Portfolio Screening Model - Overview

The Portfolio Screening Model (PSM) is composed of two main parts:

- Dispatch Model Calculation
  - Dispatches PSE fleet and potential new resources against hourly power prices from AURORA for WA/OR region
  - Utilizes the same inputs to AURORA for plant profiles and demand
  - Uses Crystal Ball Monte Carlo simulation to achieve probability weighted results
  - 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 income statement, cash flow summary and an approximation of regulatory asset base
  - Financial data from each new resource are then consolidated
  - 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, and the revenue from market sales with the revenue requirements from the new resource portfolio over a 20-year period
  - The NPV of the 20-year strip of incremental costs to customers is then calculated at the weighted average cost of capital (WACC)
  - The NPV of the expected cost to customers are for comparative purposes only

Integrated LCP Screening Model Process Flow Chart



Net Demand Development

- Hourly demand, resource, and contract summaries extracted from Aurora for the forecast period are used to develop Net Demand
- The Net Demand is derived by taking the total demand and subtracting contract purchases/(sales) and wind projects currently being developed

Dispatchable Resources

- **The dispatchable plants are:**
  - PSE owned: Fredonia1&2, Fredonia 3&4, Frederickson 1&2, Frederickson CC, Whitehorn 2&3, Colstrip 1&2, Colstrip 3&4 and Encogen (dispatchable)
  - NUG's: March Point 2 (dispatchable), Sumas, and Tenaska
  - New resources: CCGT, Coal, and Winter Call Options
- **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.). The dispatch basis determines whether a plan runs at its Dispatch Capacity or is shut down.
  - 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	Nameplate Capacity (MW)	Heat Rate (Btu/KWh)	Forced Outage Rate (%)	VOM ($/MWh)	Fuel Cost ($/MMBtu)	Planned Outage Period (Approx.)
Fredonia 1&2	202.1	11,687	0.5%	2.0	Sumas + trans.	12 days in May
Frederickson 1&2	141.0	12,499	3.1%	2.0	Sumas + trans.	12 days in March
Frederickson CC	123.4	7,070	4.0%	2.8	Sumas + trans.	15 days in June
Frederickson DF	13.4	9,800	4.0%	2.8	Sumas + trans.	15 days in June
Fredonia 3&4	118.2	10,444	2.7%	2.0	Sumas + trans.	12 days in May
Whitehorn 2&3	134.4	12,965	4.0%	2.0	Sumas + trans.	12 days in June
Colstrip 1&2	307.0	11,045	10.8%	2.0	0.51	11 days in May & 14 in June
Colstrip 3&4	371.3	10,687	11.0%	2.0	0.58	15 days in April & 7 days in May
Encogen (Dispatchable)	113.1	9,960	0.3%	2.0	Sumas + trans.	5 days in April
March Point 2 (Dispatchable)	22.0	11,350	0.0%	2.0	Sumas	5 days in May
Sumas	133.0	8,230	0.0%	2.0	Sumas	25 days in June
Tenaska	245.0	8,184	0.0%	2.0	Sumas	31 days in May
Generic CCGT	NA	6,711	5.0%	4.8	Sumas	None
Generic Coal	NA	9,274	10.0%	3.4	0.91	16 days in May

Must Run and Renewable Resources

- The must run plants are:
  - PSE Owned: All hydro plants, Encogen & March Point MR
  - NUG's: March Point 1&2 MR
  - New generic resources: Wind and Biomass
- The Must Run plants generate power in the model when they are available regardless of variable cost
  - The must run portions of Encogen and March Point and generic biomass plants run based upon their adjusted net capacity, similar to the calculation of dispatchable capacity for dispatched 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 generation is based on the monthly availability for the average water year in the 60-year hydro data set from NWPP, the hourly dispatch shape for a 2006 base year in Aurora, and current contract terms with assumed renewals.
  - Hydro capacity and energy for Chelan PUD is assumed to be renewed at 50% when the contract expires.

Plant	Nameplate Capacity (MW)	Heat Rate (Btu/KWh)	Forced Outage Rate (%)	VOM ($/MWh)	Fuel Cost	Planned Outage Period (Approx.)
Encogen (MR)	56.6	9,960	0.3%	2	NA	5 days in April
March Point 1 & 2 (MR)	123.0	8,500	0.3%	2	NA	5 days in May
Hopkins Ridge	149.4	NA	65.1%	NA	NA	None
Wild Horse	239.4	NA	60.3%	NA	NA	None
Wind	100.0	NA	68.0%	NA	NA	None
Biomass	25.0	NA	15.0%	NA	NA	None

Must Run and Renewable Resources Continued

Wind Profiles	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%

- PSE is currently using the Cascade & Inland profile for generic wind resource availability estimates
  - Appears to be where the most promising near term projects are located

Emissions Assumptions

Emission rate (T/GWh)	SO2	NOX	CO2
Fredonia 1&2	0.001	0.201	582
Frederickson 1&2	0.001	0.201	582
Frederickson CC	0.002	0.039	411
Frederickson DF	0.001	0.055	582
Fredonia 3&4	0.001	0.201	582
Whitehorn 2&3	0.001	0.201	582
Colstrip 1&2	2.276	2.090	1,119
Colstrip 3&4	0.502	2.195	1,098
Encogen (Dispatchable)	0.002	0.039	411
March Point 2 (Dispatchable)	0.002	0.039	411
Sumas	0.002	0.039	411
Tenaska	0.002	0.039	411
Generic CCGT	0.000	0.041	411
Generic SCGT	0.005	0.057	568
Generic Coal	0.580	0.222	953
Base Cost ($/Ton)	290	-	-

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
- 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 and assets with up to 30 year life. This is compounded by the fact that our portfolio planning horizon allows asset additions to occur through year 20, effectively creating a 50 year horizon for asset life
- To deal with years 21-50 in the analysis, we use the following methodology:
  - Forecast the free cash flows (100% equity basis) from the assets for years 21 to 50
  - NPV the free cash flows to year 20 at the WACC
  - Compare the NPV at year 20 to the remaining book value at year 20
  - NPV the difference to year one at the 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
  - Emissions Cost: The emissions cost escalates year 20 cost at 2.5%

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

- Dates used for analysis period
  - Planning horizon in the model is 20 years beginning Jan. 1, 2006

- Expense / Capital escalation rates
  - Both fixed and variable O&M currently assume a 2.5% annual escalation factor
  - Acquisition capex assume a 2.5% annual escalation factor
    - ✓ The model assumes that ‘acquisition capex’, or capital expenditures related to acquiring new generation MW are financed using the debt to equity ratio supplied by PSE (57% debt to 43% equity).

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

	All in Cost ($/kW)
CCGT	$790
Coal	$1,672
Wind	$1,438
Duct Fired	$790
Biomass	$1,911

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)

Fixed Expenses ($/kW-year)	CCGT	Coal	Wind Before Trans. Solution	Duct Fired	Biomass	Wind After Trans. Solution
O&M and Fixed Transmission	57.4	126.6	50.0	57.4	66.3	87.2
Variable Expenses ($/MWh)						
VOM	2.4	3.4	4.3	2.4	13.3	4.3
Fuel Basis Differential	2.4	0.0	0.0	3.4	0.0	0.0
Total	4.8	3.4	4.3	5.8	13.3	4.3

- Finance and Regulatory assumptions
  - Cost of equity and debt (used for both the WACC and debt amortization calculations) – 10.3% and 6.96% respectively
  - WACC / After Tax WACC – 8.40% and 7.01% respectively
  - Conversion Factor (gross-up factor used in revenue requirement calculation) – 65.0%
    - ✓ Roughly equivalent to (1- Federal tax rate)
- Heat Rate and Forced Outage Rates

	CCGT	Coal	Wind Before Trans. Solution	Duct Fired	Biomass	Call Option	Wind After Trans. Solution
Heat Rates	6,711	9,274	NA	9,500	NA	12,000	NA
Forced Outage Rates	5%	10%	68%	0%	15%	NA	68%

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
  - Variable Transmission
- Fixed Costs – Fixed O&M
  - The FOM Factor provided by PSE should include 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 $/Kw) provided by PSE is inflation adjusted using the escalation factor and multiplied times the plant capacity (rather than the number of Kwh produced)
  - Fixed transmission ($/KW-year) varies with transmission scenario and timing of transmission solution
- 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 wind resources, 7 year MACRS for biomass resources,15 year MACRS for 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 57% debt
  - The interest rate is assumed to be 6.96%

- 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 WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

Integrated Conservation Screening Model - Overview

The Conservation Screening Model (CSM) is composed of three main parts:

- Conservation Load Impact and Supply Resource Calculator
  - 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 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
  - 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 20-year incremental portfolio 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 incremental costs to customers is then calculated at the 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 6.8% 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 2006 base year and are adjusted for the proper annual start date for the years 2006-2025
- The 20-year total hourly conservation impact is then subtracted from the 20-year no-conservation total demand forecast (net of PSE contracts and wind resources) 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 on 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 from 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 and PSE wind projects being developed
- **The calculated supply portfolios are dispatched against the 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 non-quantifiable 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 2026-2055 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