2013
Integrated Resource Plan
September 24, 2012
Planning Reserve Margin Methodology
Price Scenarios
Agenda

- Planning Reserve Margin Methodology
- Price Scenarios / Modeling Methodology
  - Natural Gas
  - Carbon dioxide tax
  - Electricity
Planning Reserve Margin Methodology
Study Components and Workflow

- Base Portfolio
- Range of PRM levels
- Reliability Resources (SCCT, DSM, CCCT, FOT)

System Optimizer Portfolios (one per Reserve Margin level)

- Portfolio Stochastic Reliability Simulations (PaR Model)
- Portfolio Stochastic Simulations with full market access (PaR Model)

Compare costs and reliability outcomes of different PRMs

Marginal Cost of Reliability

Select PRM Level

- Capital Costs
- Reliability Measure (EUE*)
- Expected Production Cost

*Expected Unserved Energy
System Optimizer Portfolio Development

• Planning Reserve Margin levels tested: 11% through 18% in 1% increments
• Use a base portfolio as the starting point for each PRM expansion plan
• Model allowed to select reliability resources to meet PRM levels
  – Intercooled Aero SCCTs
  – Dispatchable load control (Class 1 DSM)
  – CCCT
  – Front Office Transactions
• 20-year optimization period, 2013-2032
Stochastic Reliability Simulations

• Uses Planning and Risk production cost model operating in Monte Carlo stochastics mode
  – Number of Monte Carlo iterations (“draws”) determined by convergence analysis; i.e., point where number of draws does not change Expected Unserved Energy (EUE) results
  – Loads and outages shocked

• Single-year simulation, 2014
Stochastic Reliability Simulations

• Spot market balancing transaction capability turned off

• Reliability resource available to PaR: Northwest Power Pool reserve sharing for first hour of a reportable contingency event
  – Modeled as an emergency station in each transmission area
    • Delivers power only if the alternative is a loss of load, and only for the first hour of a loss of load event

• EUE in GWh is the primary reliability measure and key output of the runs
  – Proxy EUE stations will represent resources of last resort before loss of load occurs
    • EUE stations would be dispatched after the one-hour reserve-sharing stations
    • Energy output is used to report Energy Not Served in each stochastic iteration
Stochastic Production Cost Simulations

• Additional PaR stochastic runs used to determine the full expected production cost of each System Optimizer portfolio
  – Spot market balancing transaction capability is turned on, subject to market sales caps consistent with the Company’s GRID model net power cost simulations

• Simulations run for multiple years to capture the long-run production cost impacts of the different portfolio resource mixes
Results and Analysis

• A marginal reliability/cost curve will be developed
  – Reliability Cost = Portfolio cost divided by expected EUE ($/MWh-year)
  – Marginal Reliability Cost = Differences in Reliability Cost for successively higher PRM levels

• Marginal Reliability Cost plotted against PRM level
Price Curve Scenarios
Survey of Forecasts – Natural Gas

Henry Hub

Nominal $/MMBtu


-2 -4 -6 -8 -10 -12 -14 -16 -18 -20

Base Case (June 2012 OFPC)
Vendor.2 Base
Vendor.1 Low
Vendor.1 Expected
EIA Reference
EIA High Technically Recoverable Resources
EIA Low Estimate Ultimate Recovery
Survey of Forecasts – CO₂

Carbon Dioxide (CO₂)

Nominal $ / Short Ton CO₂

- June 2012 OFPC
- Low (No CO₂)
- Vendor.1 Reference
- Vendor.2
- Vendor.3
- EPA: American Power Act Ceiling
- American Power Act Floor
- Vendor.1 High
- Vendor.2
- Vendor.3
Price scenarios were developed consistent with the approach used to produce official forward price curves and relies upon two electric sector simulation models – the Integrated Planning Model (IPM®) and MIDAS®.
Price Scenarios – IPM®

- IPM® is a North American production simulation model that optimizes electricity production costs under an environmental paradigm over time.
- Each scenario was developed from one of three static natural gas price projections: the 6/29/12 OFPC, a low-price forecast, or a high-price forecast. Each static natural gas price forecast was coupled with the $16 CO₂ tax assumptions, for a total of three IPM® simulations.
- Calibrating to natural gas demand under $16 CO₂ tax assumptions (as output from IPM®) multi-step dynamic natural gas curves were developed to capture price response under alternative CO₂ tax assumptions, requiring another three simulations. Another two simulations were run allowing IPM® to solve for the CO₂ price under a cap and trade scheme.
- IPM®’s dynamic gas price structure allows natural gas prices to respond to changes in gas demand triggered by CO₂ compliance costs.
- The following IPM® output is then fed into MIDAS®
  - WECC renewable unit builds (Wind, Solar, Geothermal, Biomass, Landfill Gas)
  - WECC thermal unit retirements
  - Gas prices
Price Scenarios – Natural Gas

Henry Hub

Nominal $ / MMBtu


-2
-1
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20

Base Case (June 2012 OFPC)
$0 CO2/High Gas
High CO2/Low Gas
C&T CO2/Base Gas
C&T CO2/High Gas
MIDAS Model Framework

**Macro Economics/Fuel**
- Electric demand
- Load profiles
- Inflation
- Discount rates
- Scarcity premiums
- Gas prices
- Oil prices

**Existing Resources**
- Location
- Unit ratings
- Heat rates
- Emission rates
- Dispatch characteristics
- Maintenance rates
- Forced outage rates

**System Constraints**
- Transmission capability
- Wheeling costs
- Operating reserves
- Planning reserves
- Hydro generation

**Policy**
- GHG
- Clean Air Interstate Rule
- Clean Air Visibility Rule
- Western Regional Air Partnership
- Renewable Portfolio Standards

**New Resource Options**
- Technology types
- First year of availability
- Cost-to-build
- Financing costs
- Operating costs
- Tax incentives
- Emission characteristics

**MIDAS**
Chronological Hourly Dispatch of Western Interconnect

**Electricity Price Forecast**
Price Scenarios – MIDAS®

- In the base case the first 72-months are represented by market forwards. Alternative forecast scenarios utilize third party natural gas price forecasts for the entire curve.

- MIDAS®, as licensed from Ventyx, is an hourly chronological dispatch model covering the Western Electricity Coordinating Council (WECC).

- MIDAS® balances supply with demand, while observing operational and transmission constraints, it solves for the regional marginal cost for each hour through the study period. MIDAS® is configured with sixteen regions within WECC.
Price Scenarios – MIDAS®

Palo Verde Flat

Nominal $/MWh

$0 CO2, High Gas
High CO2, Low Gas
Cap & Trade - Base Gas
Cap & Trade - High Gas


$0.00 $20.00 $40.00 $60.00 $80.00 $100.00 $120.00 $140.00 $160.00 $180.00
Price Scenarios – MIDAS®

MidColumbia Flat

Nominal $/MWh


- $0 CO2, High Gas
- $16 CO2, Base Gas
- High CO2, Low Gas
- Cap & Trade - Base Gas
- Cap & Trade - High Gas