2008 Integrated Resource Plan
Public Meeting

May 22, 2008

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

Agenda

- Update to the 2008 IRP Modeling Plan
- Case Definitions for Portfolio Development
- Natural Gas and Electricity Forecasts
- Resource Characterization
  - Supply side resources
  - DSM Supply Curves

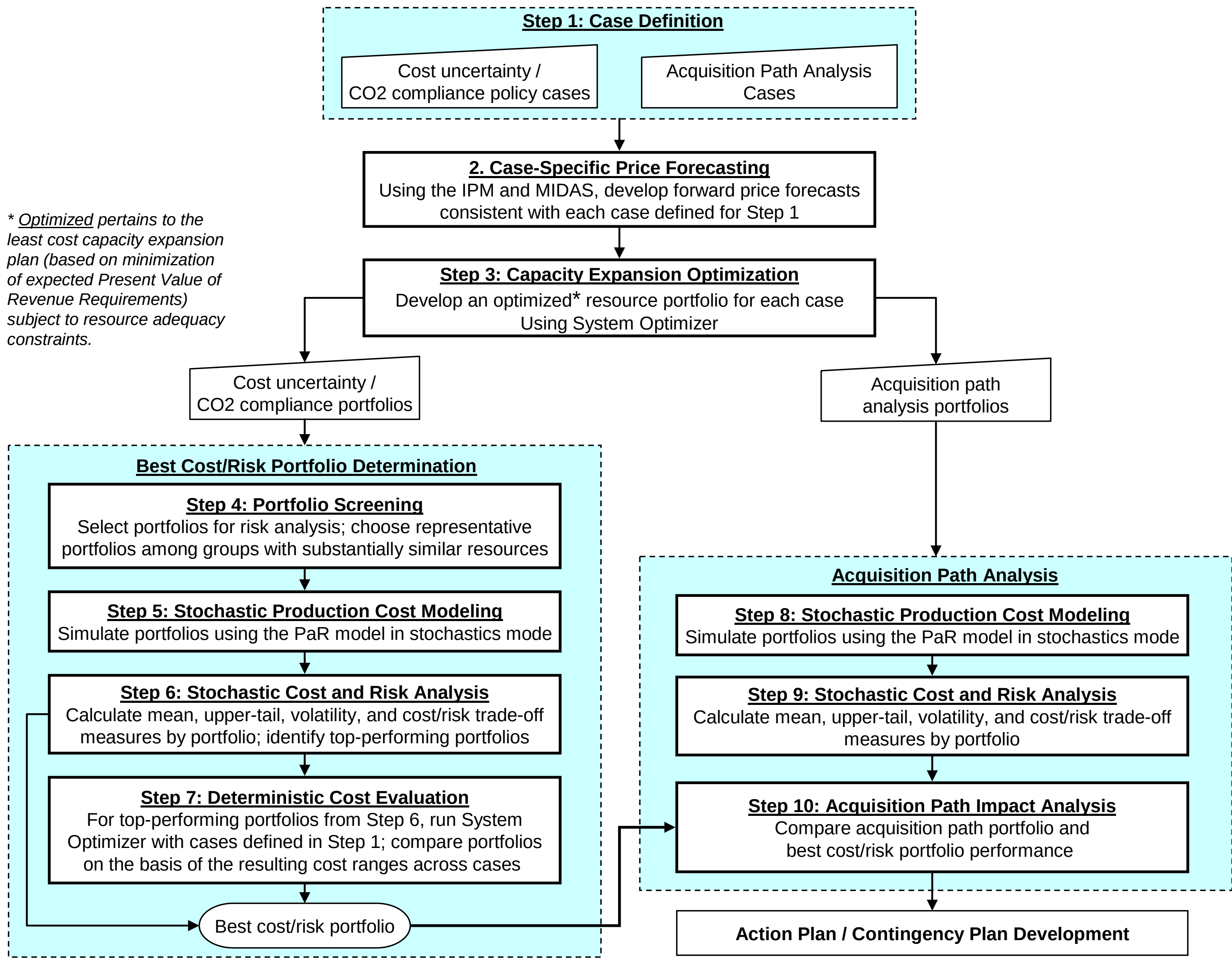
Update to the 2008 IRP Modeling Plan

Pete Warnken

Walk-through of Updated IRP Improvement Strategy Paper

- Updated paper sent Monday, May 19
  - Terminology clarifications
  - Modeling process description expanded
    - Explanation of the role of input assumption cases (tied to Case Definition paper)
    - Role of IPM model for linking CO_2 costs to other IRP model inputs
    - Details on acquisition path analysis
    - Change to CO_2 cost analysis using the Planning and Risk model
    - Definition of the new risk-adjusted cost measure included
  - IRP/business plan schedule
    - Deadline for completion of Planning Scenario 1 portfolio modeling moved up; timing impact on modeling the cases
  - Firm date for load forecasting meeting established (June 26); will also present the capacity and energy balances at this meeting

Update to the 2008 IRP Modeling Plan



Case Definitions for Portfolio Development

Pete Warnken

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Strawman Cases

- Tentative upper limit of 42 cases established
- 41 cases defined by the Company for discussion
  - Planning Reserve Margin (PRM) analysis
    - Discussion item: different PRMs by control area?
  - Cost uncertainty analysis
    - Combination of CO_2 cost, gas/electricity price, and resource capital cost assumptions
    - Discussion item: treatment of load growth forecast assumptions; comparability issue when portfolios include different amounts of total installed capacity
  - CO2 compliance policy evaluation
    - Model the rules for a specific legislative proposal (e.g., Lieberman-Warner Climate Security Act of 2008) vs. a proxy that averages compliance rules across several proposals
    - Oregon HB 3543 CO_2 targets

Strawman Cases

- Acquisition Path Analysis
  - Alternative resource constraint assumptions
    - Stringency of CO_2 regulations: cap trajectory, allowance allocation, safety value provisions, etc.
    - Renewable portfolio standard (RPS) requirements
    - Availability of clean baseload technologies
    - Extent of demand-side management (DSM) achievable potential
    - Reliance on price-responsive DSM programs as a firm capacity resource
  - Alternative load growth assumptions
  - High portfolio cost boundary conditions
  - Use of a sustained-peaking period for peak capacity planning (Utah commission requirement)
- Cost reference
  - No RPS with different CO_2 cost assumptions (Utah commission requirement)
  - 2007 Business Plan reference case

Natural Gas and Electricity Forecasts

Rick Link

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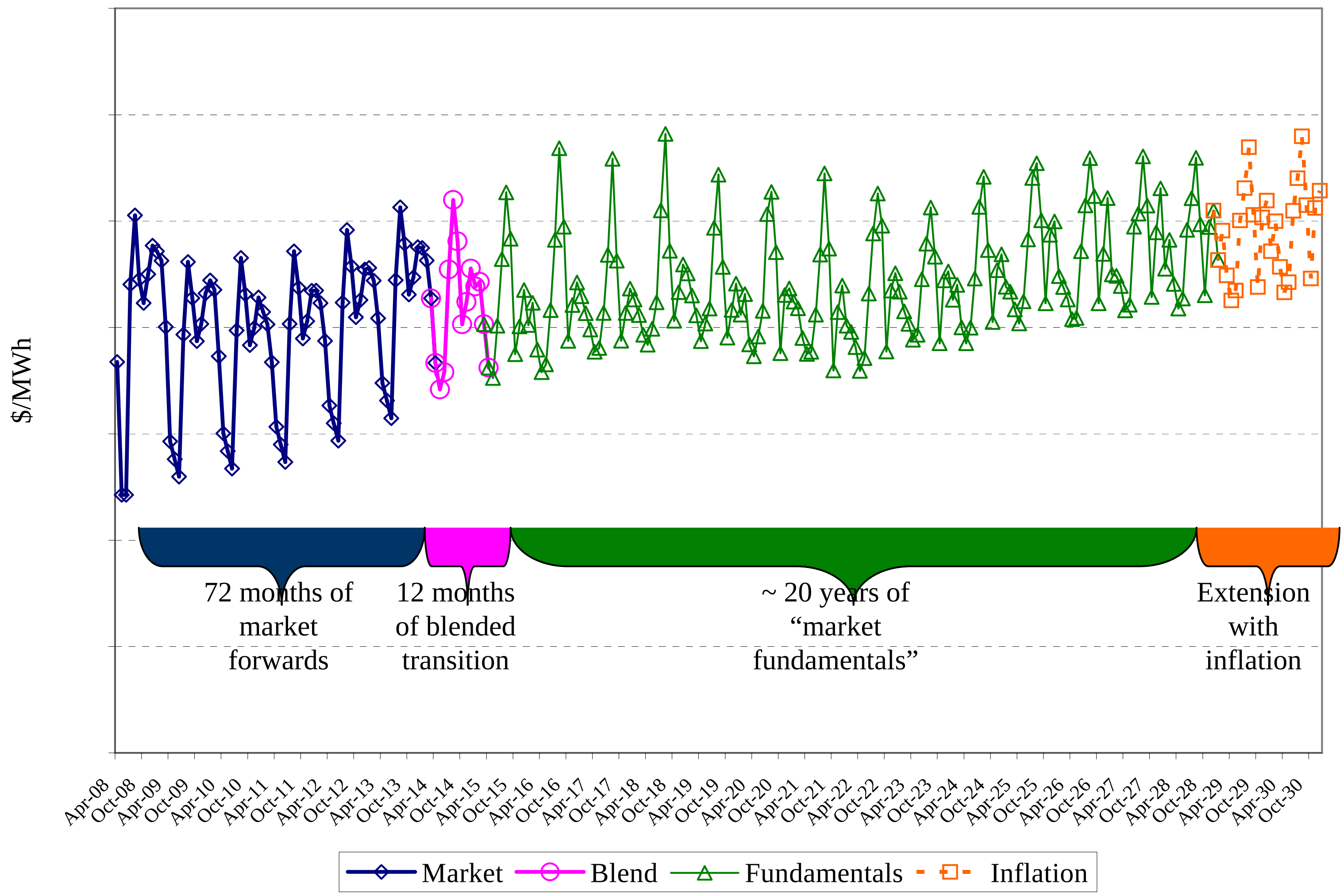
Forward Price Curve Overview

- A single forward price curve is used throughout the company
  - Avoided cost filings (up to 20-year term)
  - Regulatory filings including net power costs (up to 2 years forward)
  - Quarter-end financials including FAS-133 contracts for SEC and FERC filings (20 years forward)
  - Natural gas and electricity position management (54 months forward)
  - Long-term resource planning through the integrated resource plan and business plan (20+ years forward)
  - Commercial transaction valuations (term of contract)
  - Asset valuations (useful life of asset)
- The forward price curve undergoes rigorous review and validation
  - Internal risk management
  - External auditors
  - Internal auditors

Forward Price Curve Overview

- The forward price curve contains multiple points of delivery (POD)
  - 5 primary electricity PODs (MidC, COB, NP15, SP15, Palo Verde)
  - 11 secondary electricity PODs (basis from primary PODs)
  - 19 natural gas PODs
- Update frequency
  - The forward price curve is updated daily to reflect changing market conditions
  - The official forward price curve is a "snapshot" of the daily curve
    - As of a given point in time (generally quarter-end)
    - For a subset of PODs (to protect the commercial interest of the front office)

Forward Price Curve Components



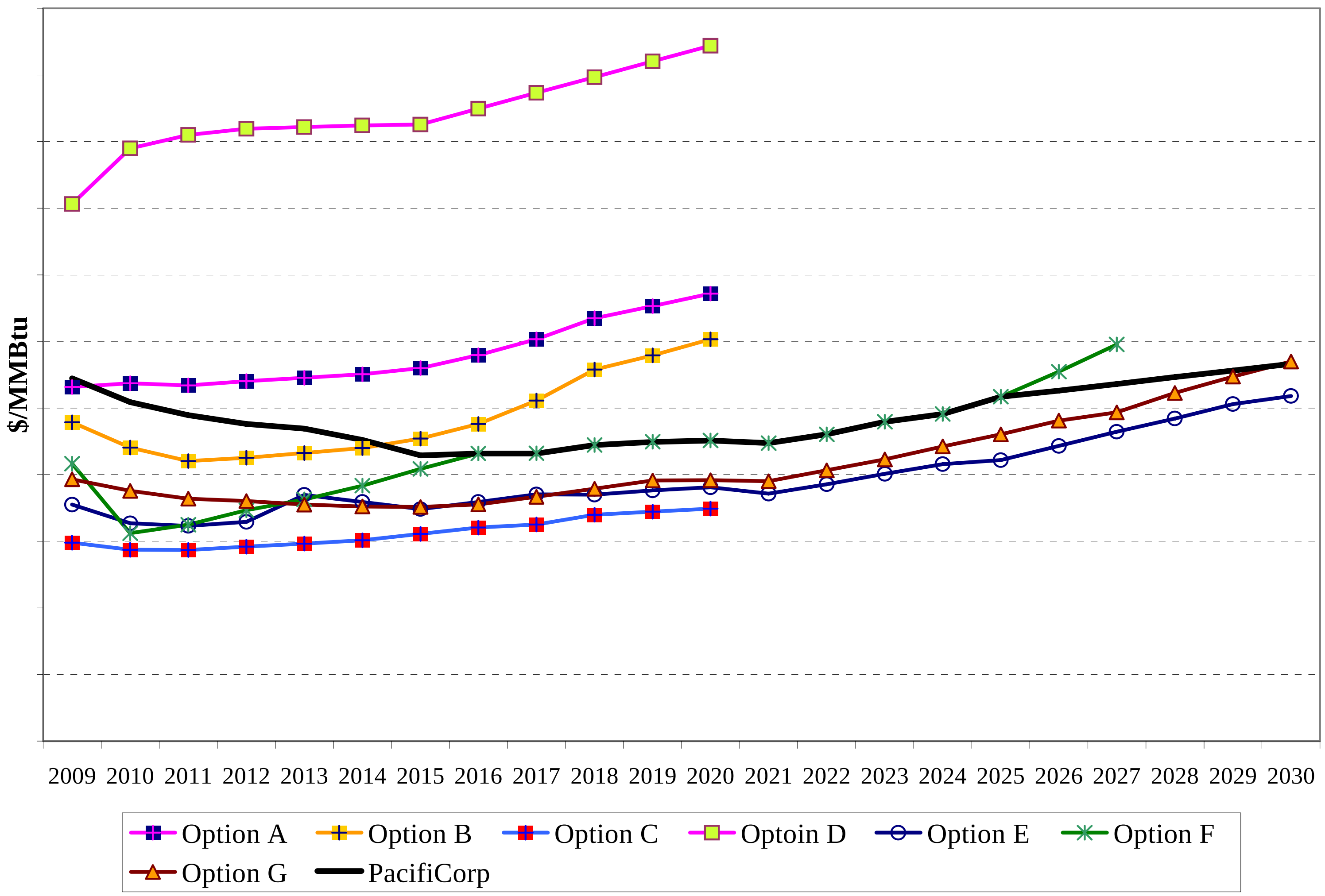
Market Fundamentals Forward Price Curve

- Beyond the 72-month market forwards portion of the forward price curve, electricity prices are modeled using MIDAS
  - MIDAS, which is licensed from Ventyx, is an hourly chronological dispatch model covering the Western Interconnect
  - The model balances supply with demand, while observing operational and transmission constraints, to find the price setting marginal operating cost by region for each hour through the study period
  - The assumptions in MIDAS most influential to the electricity forward price curve forecast include natural gas prices, carbon dioxide prices, and the resource supply mix
- Beyond the 72-month market forwards portion of the forward price curve, natural gas prices are based upon long-term third party forecasts
  - The natural gas prices are used in MIDAS to produce a consistent electricity price forecast
  - Delivered natural gas prices reflect projected basis differentials and transportation charges/capacity charges

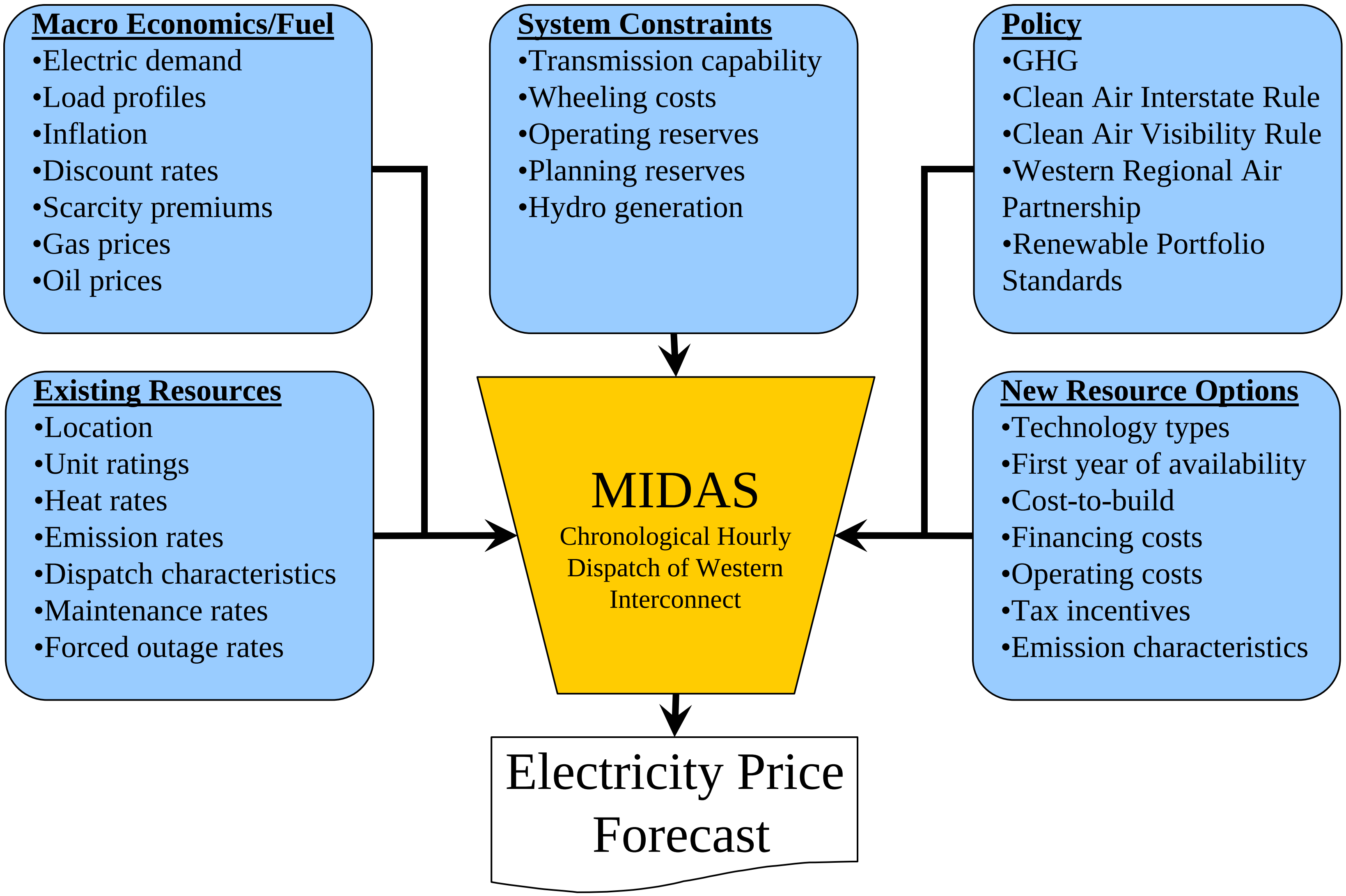
Gas Price Methodology Overview

- Gas prices used to develop PacifiCorp's long-term forward curve are traditionally based upon a number of third party projections
  - PIRA
  - Wood Mackenzie
  - Cambridge Energy Research Associates (CERA)
- A range of factors are considered when adopting the forecast or combination of forecasts for use in PacifiCorp's long-term forward curve
  - Underlying fundamental assumptions (i.e. gas balances)
  - Documentation (i.e. rationale behind assumptions)
  - Peer-to-peer price comparisons (i.e. outliers)
  - Forecast release date (i.e. is the forecast outdated?)
  - Forecast horizon (i.e. how far are prices projected?)

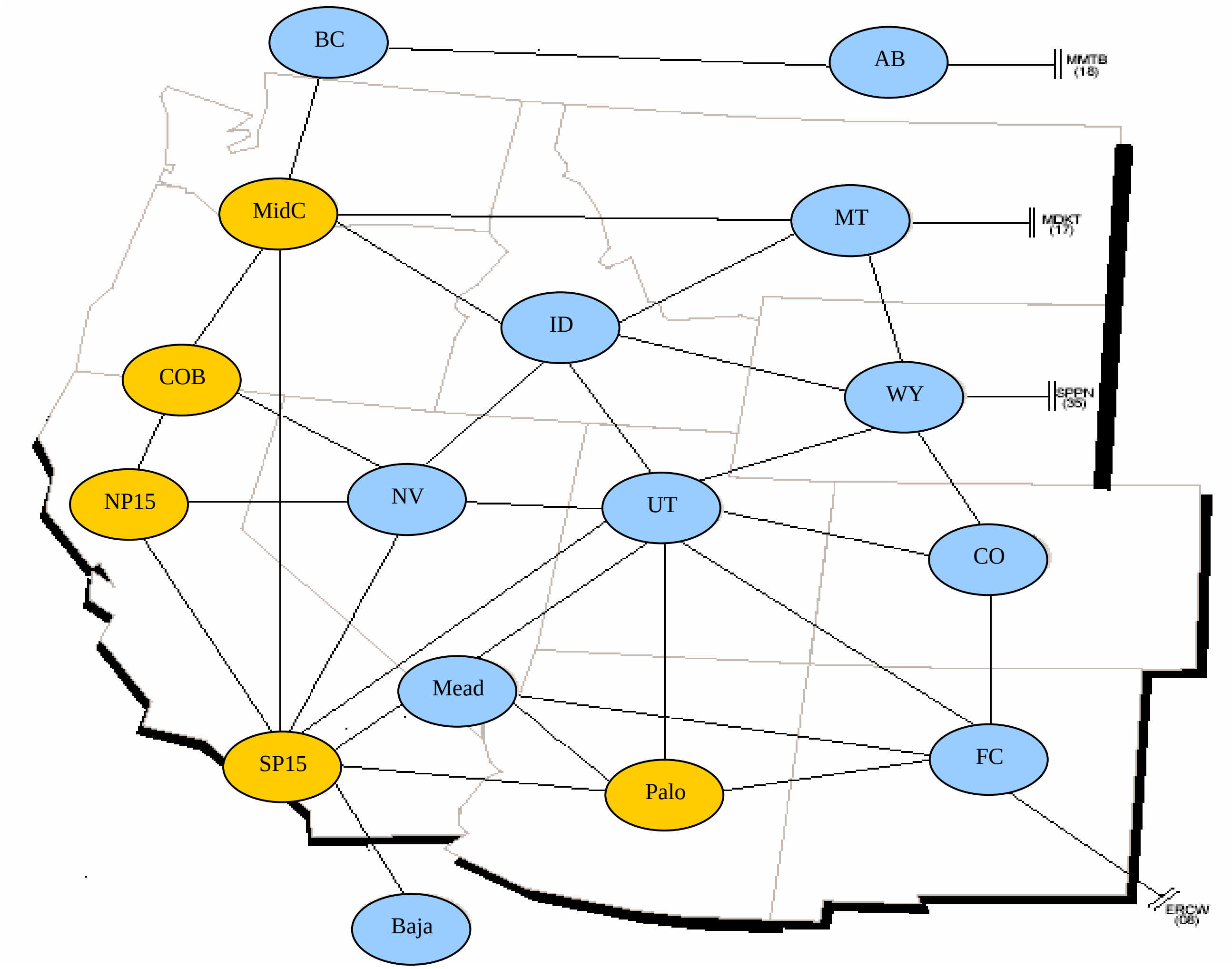
Henry Hub Natural Gas Forecast Variability



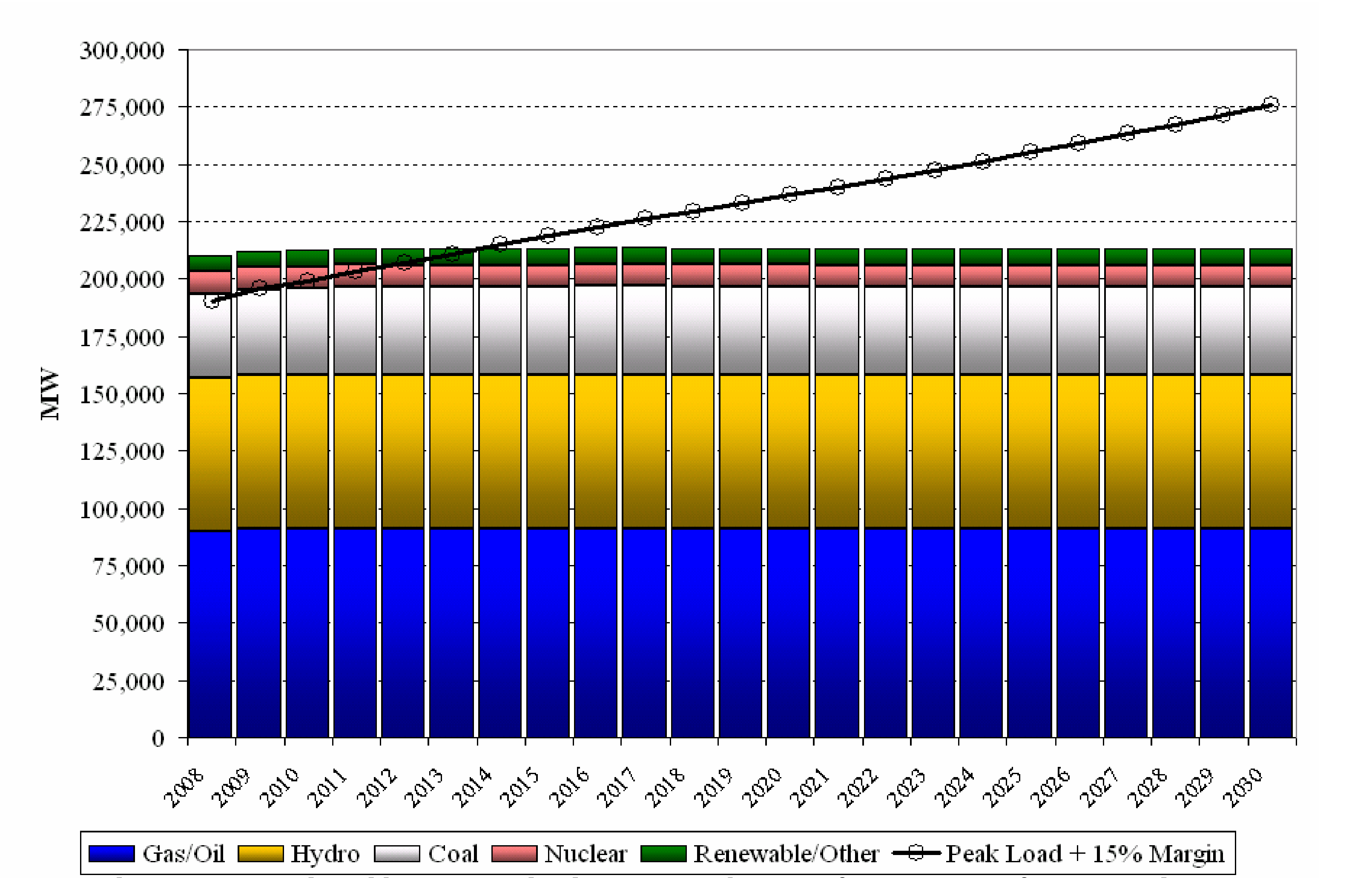
MIDAS Model Framework



MIDAS Topology

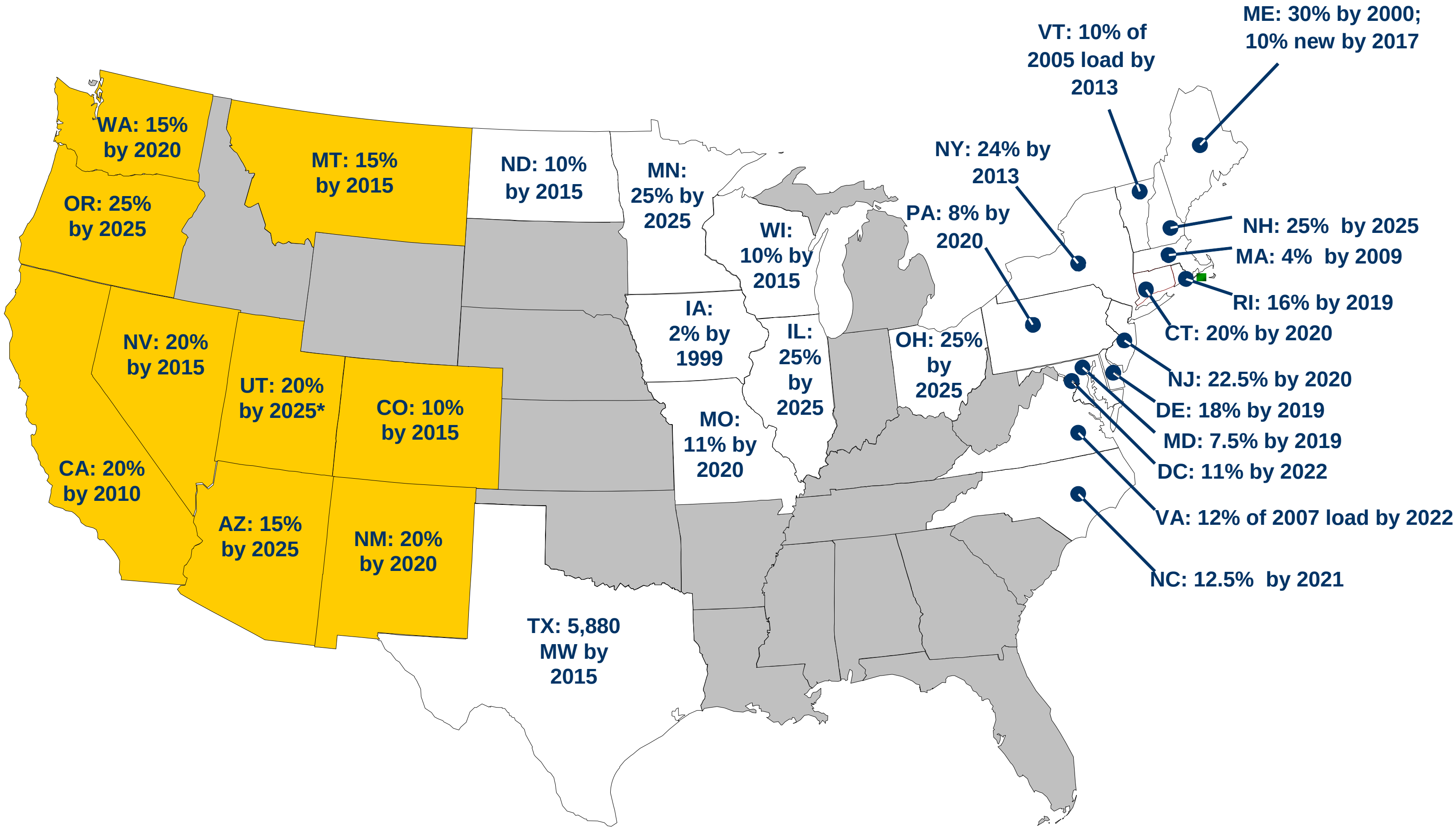


WECC Existing Resource Mix and Peak Load in MIDAS*



* Wind capacity is reduced by 80% and solar capacity by 75% for purposes of meeting planning margins.

Renewable Portfolio Standards Covered in the MIDAS Forecast



* The Utah RPS target is applied to adjusted retail sales and only to the extent that resources acquired to meet the RPS are cost effective.

Supply Side Resources

Jim Lacey

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Supply Side Resource Table

- Assumptions
  - Capital costs incorporate data from ICF International's IPM database
  - Use recent studies and benchmarks for performance and operating costs
  - 2008 dollars
  - Capital cost low estimate - 5% less than base
  - Capital cost high estimate - 20% greater than base
  - Capital cost increases compared to 2007 IRP
  - Emission profiles similar (Mercury at 90%)

Supply Side Resource Table

- Coal Assumptions
  - No new coal available till 2020
  - Carbon Capture and Sequestration (CCS) not available until 2025
  - Available only on the east side of the system
  - Capital costs up substantially (~50 to 60%)
    - Materials/Labor
    - EPC Contracting
  - CCS on existing units a negative resource

Supply Side Table Options - Coal

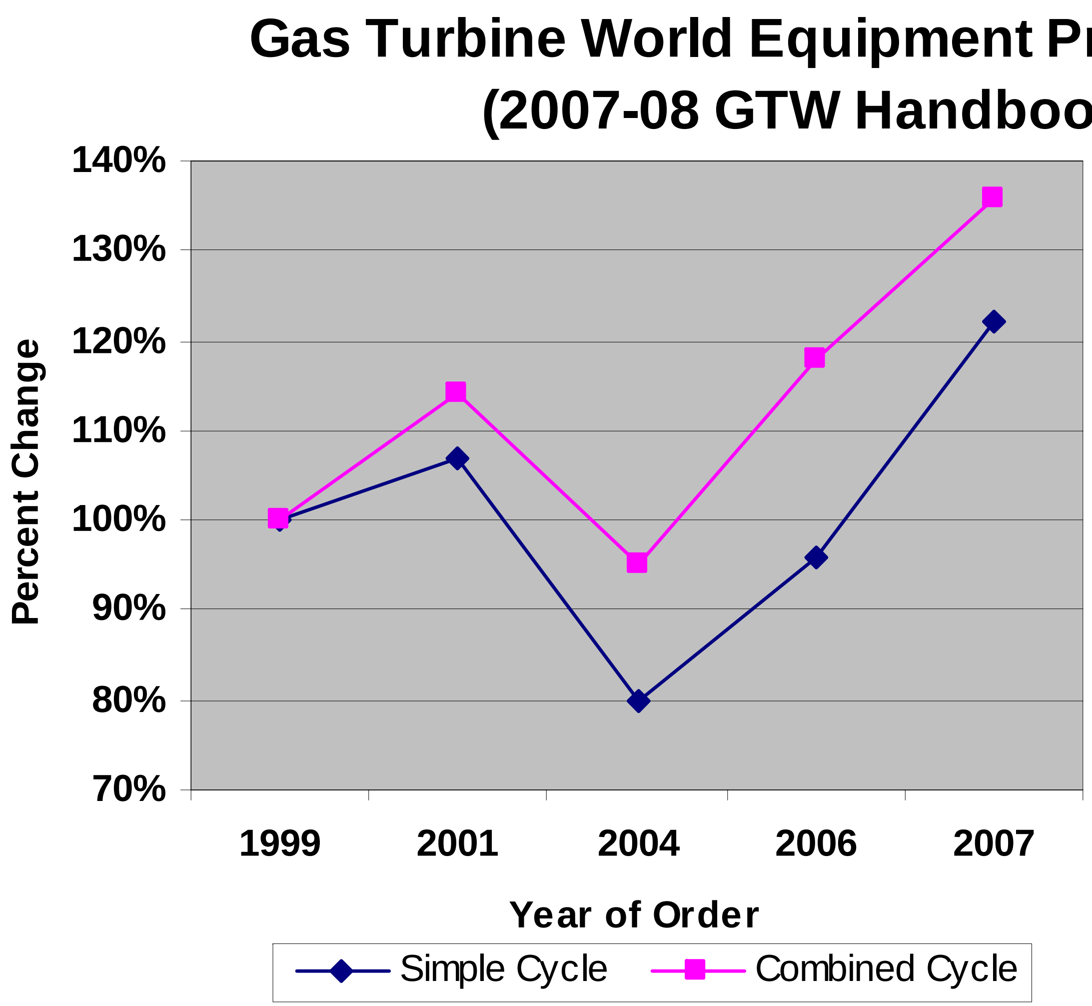
	Average Capacity MW - Not Incl. Degradation	Technology	Capital Cost Estimate in $/kW (Average)	Annual Average Heat Rate Btu/kWh HHV - Incl. Degradation
East Side Options:				
Coal				
Utah PC without Carbon Capture & Sequestration	600	PC Supercritical	$3,230	9,106
Utah PC with Carbon Capture & Sequestration	521	PC Supercritical	$4,874	13,087
Utah IGCC without Carbon Capture & Sequestration	508	IGCC - (2x1)	$4,737	8,734
Utah IGCC with Carbon Capture & Sequestration	466	IGCC - (2x1)	$6,837	10,823
Wyoming PC without Carbon Capture & Sequestration	790	PC Supercritical	$3,650	9,214
Wyoming PC with Carbon Capture & Sequestration	686	PC Supercritical	$5,508	13,242
Wyoming IGCC without Carbon Capture & Sequestration	497	IGCC - (2x1)	$5,352	8,915
Wyoming IGCC with Carbon Capture & Sequestration	456	IGCC - (2x1)	$7,508	11,047
Existing PC with Carbon Capture & Sequestration (500 MW)	(66)	PC Subcritical	$2,466	14,372

Note: The capacity shown for retrofitting CCS on existing PC plants is a net change from current capacity (proportional to 500 MW). The heat rate is the total net plant heat rate based on a nominal 10,000 Btu/kWh without CCS.

Supply Side Resource Table

- Gas Assumptions
  - Simple cycle (SCCT) and combined cycle (CCCT) options included
  - Table lists wet cooling but dry cooling available
  - Internal combustion engines included
  - Costs have risen substantially
    - ~40% for SCCT and ~70% for CCCT
    - Materials / Labor / Contract Method
    - Supply and demand for limited resources
  - Utility CHP is a Compressor Heat Recovery Application

Cost Trends – Gas Turbine World



Simple Cycle (1999-2007) Prices have climbed 20-30 percent and are beginning to rise sharply due to increasing cost of materials and manufacturing.

Combined Cycle (1999-2007) Prices never dropped as much as simple cycle plants, but they are now rising 15-20% over the last 12 months.

Supply Side Table Options - Gas

	Average Capacity MW - Not Incl. Degradation	Technology	Capital Cost Estimate in $/kW (Average)	Annual Average Heat Rate Btu/kWh HHV - Incl. Degradation
Natural Gas (4500 feet)				
Utility Cogeneration	10	Compressor Heat	$5,588	4,974
Fuel Cell - Large	25	SOFC	$1,657	6,250
SCCT Aero	79	SCCT - 2 x LM6000	$1,040	9,647
Intercooled Aero SCCT	87	SCCT - 1 x LMS100	$1,060	9,280
Internal Combustion Engines	153	Natural Gas Engines	$1,223	8,390
SCCT Frame (2 Frame "F")	302	SCCT - 2 - Frame F	$690	11,509
CCCT (Wet "F" 1x1)	222	CCCT - "F" (1x1)	$1,504	7,223
CCCT Duct Firing (Wet "F" 1x1)	50	"F" Duct Firing	$614	8,869
CCCT (Wet "F" 2x1)	506	CCCT - "F" (2x1)	$1,369	7,021
CCCT Duct Firing (Wet "F" 2x1)	64	"F" Duct Firing	$628	8,557
CCCT (Wet "G" 1x1)	333	CCCT - "G" (1x1)	$1,422	6,810
CCCT Duct Firing (Wet "G" 1x1)	72	"G" Duct Firing	$602	9,021
CCCT Advanced	400	"H" Technology	$1,407	6,615

Supply Side Resource Table

- Renewable Assumptions
  - Additional options considered
    - Biomass / Regional Wind / Hydrokinetic / Multiple Solar
  - Solar includes thermal and photovoltaic (PV)
  - Geothermal based on Blundell 3
  - Wind capacity factors based on region
  - Costs have increased (~40%)
    - Scarcity affected previous wind estimates
    - Less labor intensive
  - Estimates do not include tax benefits
  - Capital cost estimates largely project based
  - Nuclear included as an alternative generating option

Supply Side Table Options - Renewable

	Average Capacity MW - Not Incl. Degradation	Technology	Capital Cost Estimate in $/kW (Average)	Annual Average Heat Rate Btu/kWh HHV - Incl. Degradation
Other - Renewables				
Wyoming Wind (38% CF)	100	1.5 to 2.5 MW Turbines	$2,268	n/a
Utah Wind (29% CF)	100	1.5 to 2.5 MW Turbines	$2,268	n/a
Oregon / Washington Wind (35% CF)	100	1.5 to 2.5 MW Turbines	$2,407	n/a
East Side Geothermal	35	Dual flash	$5,038	n/a
Biomass	50	Boiler	$3,684	10,979
Battery Storage	20	Advanced Batteries	$1,926	12,000
Pumped Storage	350	Pumped Hydro	$1,638	13,000
Compressed Air Energy Storage (CAES)	350	CAES	$1,036	11,670
Nuclear	600	Advanced - Fission	$5,461	10,710
Hydrokinetic (Wave) - 21% CF	100	Floating Buoy	$6,000	n/a
Solar Concentrating (PV) - 30% CF	50	Concentrating PV	$7,110	n/a
Solar Concentrating (natural gas backup) - up to 60% CF	200	Thermal (trough)	$4,350	11,750
Solar Concentrating (thermal storage) - 47% CF	200	Thermal (trough)	$4,350	n/a

Demand Side Resources

Jeff Bumgarner / Don Jones / Stan Williams

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Demand Side Supply Curves – General

- June 2007 Potential study provided a broad estimate of the size, type and location of demand side resources
- Potential study provided energy efficiency estimates using given set of valuation screens (2007 IRP east and west decrement values + 15%)
- Potential study utilized 2007 IRP proxy supply curves date to estimate magnitude of capacity based resources
- Better estimate of how much demand side resource is cost effective comes from converting potential study estimates into supply curves and utilizing IRP models to compare them to supply side resources
- Potential study information on all resources including capacity based, (Class 1 & 3) and energy based (Class 2) DSM and supplemental (distributed generation and renewables) are being converted into supply curves with adjustments as noted

Demand Side Supply Curves – General

- Supply curves are a compilation of point estimates, each of which includes:
  - Resource quantity first year (MW or MWh)
  - Resource quantity over time (measure life for energy efficiency)
  - Levelized cost ($/MW-yr or $/MWh basis)
  - Availability & characteristics
    - Year available – all resources
    - Hours of the year capacity reductions are available (event hours, seasonality and total hours for capacity resources)
    - Annual hours energy savings occur (determined by load shapes for energy efficiency)

- Supply curves are designed to “look like” discrete generation plants to the IRP models.

Demand Side Supply Curves For Energy Efficiency

- Potential study done at measure level: appliance, motor, air compressor, etc., and the facility level, residential, small offices, etc. Best practice for energy savings estimates. Very granular
  - Six residential facility types, 24 commercial facility types, 28 industrial facility types, two irrigation (new and existing).
  - 62 unique residential measures, 78 unique commercial measures, 13 unique industrial measures, 3 unique irrigation measures
  - All measures across all facility types and states ~ 12,500 measures.
  - Costs are total resource costs which includes both measure and administrative costs levelized over measure life at utility cost of capital. Consistent with supply side costs.

Demand Side Supply Curves - Energy Efficiency

- Preliminary estimate of energy efficiency potential in the study (excludes Oregon) over 20 years (base case)

- **Technical** – all possible installations
  - 1,130 MWa or 9,898,800 MWh
- **Economic** – preliminary adjustment based on 2007 IRP valuations
  - 913 MWa or 7,997,880 MWh
- **Achievable** – adjustment based on third party vendor review of best practices data and primary research with our customers
  - 502 MWa or 4,397,520 MWh

- Lighting impacts from 2007 energy legislation not deducted from potential estimates given schedule and uncertainty over final bill. Impacts will be quantified and included in future runs.

Demand Side Supply Curves - Energy Efficiency

- **First challenge:** *Can we model ~ 12,500 energy efficiency resources in addition to Class 1 and Class 3 resources?*
  - **No** - exceeds upper limit on modeling capability
  - **Solution:** Identified levelized cost breaks in granular data and compile resources bundles
    - **Bundle one:** up to $0.07/kWh
    - **Bundle two:** $0.07 to $0.18/kWh
    - **Bundle three:** $0.18 to $0.26/kWh
    - **Bundle four:** $0.26 to $0.83/kWh
    - **Bundle five:** $0.83 and above/kWh

    (Bundles one–three:) ~ 85% of resources in these 3 bundles
- Bundles were developed based on technical potential. Economic screen was removed
- Revised study achievable assumption to 85% - best proxy for high achievable case and appropriate for model inputs
- 5 cost bundles x 5 states x 20 years = 500 bundles (before we allocate to load bubbles – see below)

State	*Goshen*	*Utah*	*Walla*	*Westmain*	*Wyoming*	*Yakima*
CA				*100%*		
OR			4%	96%		
ID	42%	58%				
UT		100%				
WA			25%			75%
WY		18%			82%	

Demand Side Supply Curves - Energy Efficiency

- Each bundle assigned weighted average load shapes using load shapes consistent with potential study
- Each bundle has a weighted average measure life using measure lives consistent with potential study assumptions
- How about Oregon?
  - Work underway with Energy Trust of Oregon (ETO) to formulate their fall 2007 SB 838 (no funding limits) update data into comparable supply curves.
  - Inputs are based on ETO assessment of economic and achievable. Trust economic screen uses Pacific Power west side decrement values from last IRP.
  - Unlike other energy efficiency resources, Oregon resources bound by point estimates provided by the Trust
  - Step closer to seamless integration. Using better data (not funding constrained) and consistent modeling using supply curves.

Demand Side Supply Curves – Modeling Energy Efficiency

Two types of input files from Quantec

- One file providing state, price bundle, in-service year, and measure life of resources
  - Costs nominal for in-service year
- 25 load shape files for five states and five price bundles

System Optimizer

- 8 bubble/states x 5 bundles x 20 years = 800 resources
- Each load shape is an 8,760 hour file (2008 calendar)
  - Values are percentage of maximum hourly savings
- Contribution to peak computed from load shapes
- Model run for 20 years to pick resources
  - Resources extended over measure life
  - Fractional resources can be selected
- Selected resources transferred to Planning and Risk

Planning and Risk

- Detailed 20-year load shapes
- Model as fixed forward contracts under varying economic, supply side and environmental assumptions

Demand Side Supply Curves - Class 1 and 3 resources

- Class 1 and 3 supply curves consistent with prior IRP proxy supply curve study (except as noted below)
- Class 1 treated consistently with Class 2
- Class 3 treated consistently with prior IRPs
- State to load bubble percentages same as Class 2 percentages
- Key assumption changes for irrigation load control noted below
  - Idaho 25% program participation rate from study changed to 80% based on current participation
  - Pacific Power 25% program participation assumption remains unchanged due to smaller pumps.
  - Study estimates 308 MW of coincident peak technical potential for Rocky Mountain Power.
  - Program is assumed to be all dispatchable beginning in 2009 for all states
  - Program costs: study assumption of $42/kW-year has been changed to reflect current estimates of about $45/kW-year

Demand Side - Class 1 and 3 Resources Modeled

Class	Program Names	Program
Class 1	DLC-RES-AC-WH	Combination residential and small commercial air conditioning/water heating control
Class 1	DLC-RES-AC	Residential and small commercial air conditioning only load control
Class 1	TOU-RES	Residential time of use rates
Class 1	CPP-RES	Residential critical peak pricing
Class 1	DLC-Com	Commercial/Industrial direct load control program
Class 1	Irrigation	Irrigation load control (dispatchable program rather than scheduled forward program modeled in study)
Class 1	Sched-TES	Thermal energy storage

Class 3	Curtailable Load	Commercial and Industrial curtailment tariff program (250 kW and larger customers)
Class 3	Demand Bidding	Commercial and Industrial Demand buyback program
Class 3	CPP-C&I	Small commercial critical peak pricing
Class 3	RTP-C&I	Commercial and industrial real-time pricing

Demand Side Supply Curves– Modeling Class 1 and 3

Input files from Quantec

- Hours, event and total, seasonality
- Demand reductions
- Costs

Preparation of files

- Align available hours with system coincident peaks

System Optimizer

- Model run for 20 years to pick resources
  - Resources extended over measure life
  - Fractional resources can be selected
- Selected resources transferred to Planning and Risk
  - Class 1 resources selected will be transferred
  - Class 3 resources selected will not be transferred (consistent with prior IRP)

Planning and Risk

- Detailed 20-year load shapes
- Model as fixed forward contracts under varying economic, supply side and environmental assumptions

Distributed Generation

Dan Swan / Stan Williams

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Distributed Generation (DG)

- Key data from the 2007 Quantec DSM Potentials Study
  - Economic MW Potential
    - By state and technology
      - 6 Combined Heat and Power (CHP) categories
      - 3 solar categories: attic fans, solar water heaters, solar rooftop photovoltaic
      - 2 dispatchable standby generation categories (DSG): existing and new
  - Apply installed cost reduction (% / yr)
    - Reciprocating engine at 1%
    - Microturbine at 3%
    - Fuel Cell at 5%
    - Gas Turbine at 1%
  - Solar Generation Profiles
    - 12% to 14% Capacity Factor
  - Dispatchable standby generator operation: 80 Hours on-peak split summer and winter
  - 15% Administrative Charge for Capital
    - Dispatchable standby generators - 15% Administrative Charge for both capital and fixed O&M

IRP Adjustments to Quantec Data

- Quantec Potential Study adapted for 2008 IRP
  - DG Resource's modeled on Total Cost Basis
  - Industrial Biomass and Anaerobic Digesters
    - priced at PacifiCorp's Avoided Cost
    - Quantec's resource cost lower but capped at expected cost Company would pay for a Qualifying Facility
  - Resources by state mapped to transmission areas ("bubbles")
    - Same percentages as used for Class 2 DSM
  - Avoided Transmission & Distribution Costs: $23 /kW-year
    - WUTC requirement to include such avoided costs in the IRP
  - Revisited costs, especially available federal and state incentives
  - Tax benefits - Federal
    - Microturbine $200 / kilowatt capacity
    - Fuel Cell $500 / 0.5 kilowatt of capacity

IRP Adjustments to Quantec Data (continued)

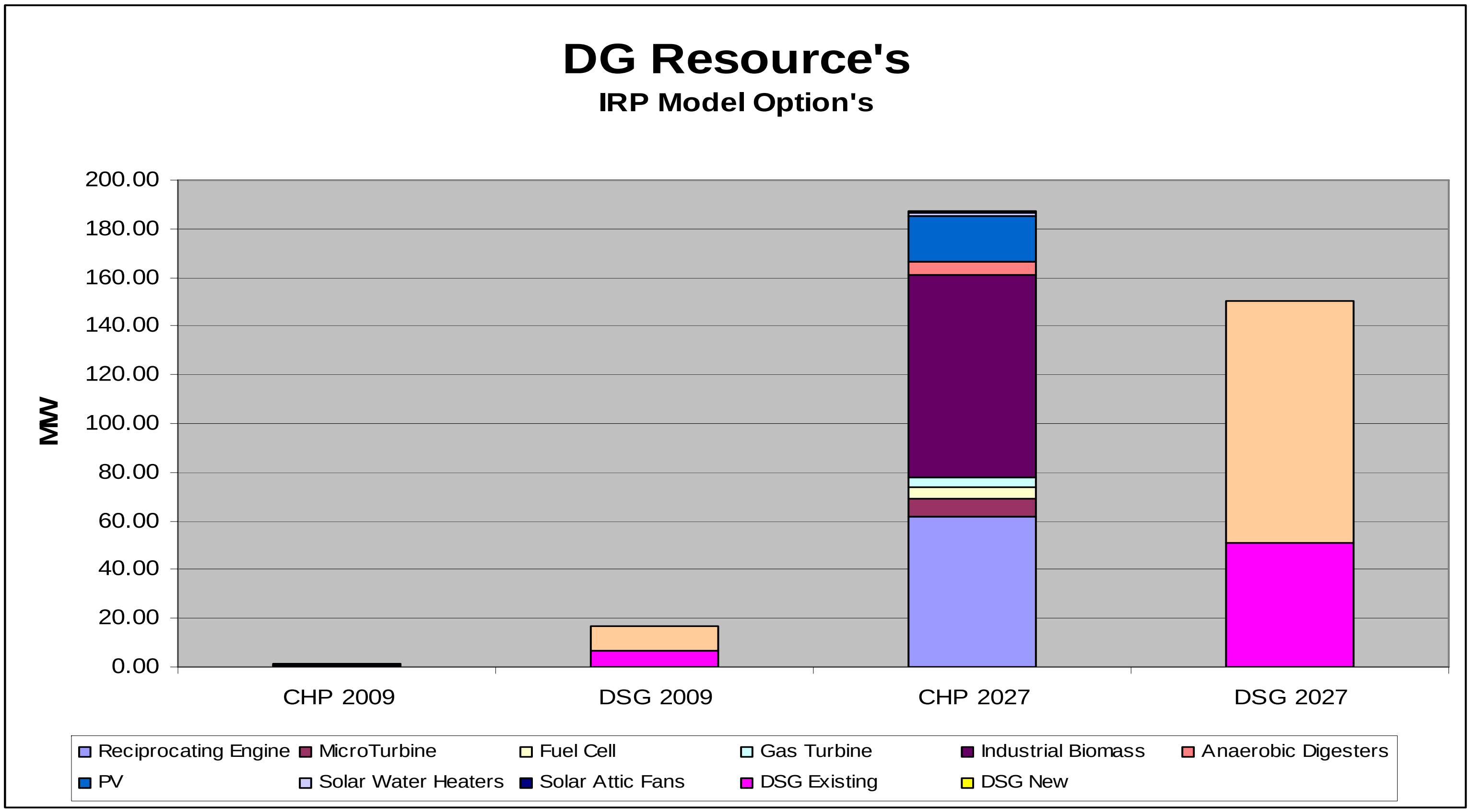
- Solar Renewable Benefits
  - Do not qualify for Production Tax Credits - not Utility Scale
  - Excluded Solar Attic Fans
  - Utah Benefits
    - Residential - Federal 30% of Investment up to $2,000; Utah up to $2000
    - Commercial - Federal 30% of Investment
    - PacifiCorp schedule 107 excluded (cost to customers)
  - Oregon Benefit
    - Residential - Federal 30% of Investment up to $2,000; Oregon credit, Oregon Trust $.02/watt up to $10,000 (funded by customers)
    - Commercial - Federal 30% of Investment; Business Tax Credit (50% of Project investment up to credit of $10 million spread over 5 years); Oregon Trust $.0125/watt but limited by size (funded by customers)
  - Benefits Equates as reduction to Capital Cost
    - Oregon 80% and Utah 30% including State Benefits, All Other States 25% (Federal only)
  - No REC value under investigation
- 2008 Tax benefits assumed to be renewed and carried forward
- Trended Quantec data after 2027
- Natural Gas price’s linked to 2008 IRP forecast
- Capital Recovery Rate linked to 2008 IRP forecast

Distributed Generation - Challenges

- Study contains several small resources under 6 MW of economic potential
  - Solar Attic fans 0.5 MW
  - Solar water Heaters 1.4 MW
  - Gas Turbine 4.2 MW
  - Fuel Cell 4.3 MW
  - Anaerobic Digesters 5.2 MW
- 1,700 possible resource options if adding a specific resource potential for each year
- Requirement is to screen all CHP and DSG resource options
- System Optimizer setup solution
  - Divided the economic potential in 2030 by the number of forecast years to create an average MW size for technology by bubble (unit)
  - SO Model given number of units available per year and total units available

Distributed Generation Resource Potential

- By 2027, CHP resource options grow to 187 MW, while DSG resource options grow to 150 MW



DG – Levelized Cost

- Levelized cost in Quantec study before tax benefits

Levelized Cost (cents /kwh)

	East	West	New	Existing
Reciprocating Engine	$ 0.08	$ 0.08		
MicroTurbine	$ 0.11	$ 0.11		
Fuel Cell	$ 0.16	$ 0.16		
Gas Turbine	$ 0.08	$ 0.08		
Industrial Biomass	$ 0.03	$ 0.03		
Anaerobic Digesters	$ 0.07	$ 0.07		
PV	$ 0.79	$ 0.85		
Solar Water Heaters	$ 0.35	$ 0.38		
Solar Attic Fans	$ 6.94	$ 7.51		
DSG ($/KW-year)			$52	$61

DG – IRP Model Input

- Administrative Costs, Federal & State Tax Benefits and T&D Credit added into Capital Cost in System Optimizer Model
- Sample below shows data for Washington (state tax not applicable)

	CHP - Reciprocating Engine	CHP - Gas Turbine	CHP - Microturbine	CHP - Fuel Cell	CHP - Commercial Biomass, Anaerobic Digester	CHP - Industrial Biomass, Waste	Solar - Rooftop Photovoltaic	Solar - Water Heaters	Solar - Attic Fans	Dispatchible Standby Generators Existing	Dispatchible Standby Generators New
Capital Cost ($/kw/year)											
Resource	1,969	1,838	2,831	5,697			9,000	3,500	54,000	250	175
Admin Cost	295	276	425	855			1,350	525	8,100	38	26
Federal Tax Benefits	0	0	(200)	(1,000)			(2,250)	(875)	0	0	0
T&D Credit	(225)	(225)	(202)	(154)			(264)	(202)	(154)	(211)	(211)
Total	$2,039	$1,889	$2,854	$5,398			$7,836	$2,948	$61,946	$76	($10)
1st Year Capital Recovery Rate	10.23%	10.23%	11.41%	14.96%			8.72%	11.41%	14.96%	10.88%	10.88%
Economic Life	20	20	15	10	15	15	25	15	10	20	20
Variable O&M					Avoided Cost	Avoided Cost					
Fixed O&M ($/kw-year)	$79.00	$58.00	$71.00	$17.00			$100.00	$0.00	$0.00	$8.63	$5.75

Next Steps

- Meeting tomorrow: CO_2 risk
  - Different Utah Room: NTO 215L (Above Lobby)
  - Portland: LCT 956
- Action Items
  - Finalize cases and modeling approach based on meeting feedback and written comments received by 5/30/08
  - Distribute final versions of IRP improvement strategy and case definition papers