Why Rates Don't Always Produce the Expected Revenues and Margins

Eric Blake

The Prime Group, LLC

Margin Variations

- Margin = Revenue – Expenses
- Concern is mainly with reductions in margins
  - Revenue decreases
  - Expense increases

Revenue Variations

- Revenue = Price x Quantity
- Compare revenue levels to test year revenue levels
  - Total revenue
  - Per unit revenue
  - Revenue per customer class
- Look for revenue variations mainly on the quantity side (billing units)

Expense Variations

- Compare expenses to test year levels by RUS account number
- Explore accounts with significant increases
- Review pro forma adjustments from test year to ensure that these adjustments are tracking actual cost changes

Causes of Revenue Variations

- Not reconciling test year revenues in a cost of service study
- Large error in revenue reconciliation
- Test year billing determinants may be inaccurate which can result in the new rates not producing the anticipated revenues

Revenue Reconciliation Example

Residential				
			Current Rate	
Description		**Billing Units**	**Rate**	**Calculated Billings**
Service Charge/Minimum Bills				
	All Customers	397,218	$ 26.10	$ 10,367,389.80
Energy Charge		kWh		
	Distribution Delivery	465,879,239	$ 0.0185	$ 8,618,765.92
	Purchased Power	465,879,239	$ 0.0613	$ 28,558,397.35
	Tracker	-		$ 567,087.12
Sub-total energy charge:		931,758,478		$ 37,744,250.39
	Total Billings			$ 48,111,640.19
	Per Bill Frequency Reports			$ 48,073,227.57
	Difference			$ (38,412.62)
	Percentage Difference			-0.08%

Revenue Reconciliation Example

Description	Number of Lights	Current Rate: Rate	Current Rate: Calculated Billings
Standard Offer Charge			
175W MV	-	$ 5.27	$ -
100W HPS	-	$ 3.01	$ -
Distribution Charge			
All Lights	43464	$ 1.06	$ 46,071.84
Customer Charge			
All Lights	43464	$ 4.27	$ 185,591.28
Franchise Tax			
175W MV	182	$ 0.04	$ 7.28
100W HPS	43282	$ 0.02	$ 865.64
Pole and Misc. Additional Charge			
Additional Pole	41151	$ 2.52	$ 103,700.62
	Total Billings		$ 336,236.66
	Per Bill Frequency Reports		$ 654,379.48
	Difference		$ 318,142.82
	Percentage Difference		48.62%

Revenue Reconciliation Example

Description		Billing Units	Rate	Calculated Billings
Customer Charge				
	Secondary 1 Phase	-	$ 16.09	$ -
	Secondary 3 Phase	336	$ 23.01	$ 7,731.36
	Primary	88	$ 25.71	$ 2,262.48
	Large Customer	12	$ 939.00	$ 11,268.00
		436		$ 21,261.84
Energy Charge		kWh		
	Summer First 8500 kWh	1,383,172	$ 0.1085	
	Summer Additional kWh	69,462,244	$ 0.0923	
	Winter First 8500 kWh	1,923,552	$ 0.0980	
	Winter Additional kWh	91,223,796	$ 0.0831	
	Distribution First 8500 kWh	3,306,724	$ 0.0200	$ 66,134.48
	Distribution Additional kWh	160,686,040	$ 0.0130	$ 2,088,918.52
	PPCA			$ (182,578.78)
Sub-total energy charge:		163,992,764	0.012027813	$ 1,972,474.22
Demand Charge		kW		
	Standard Service > 25 kW	457,127	$ 5.72	
	Distribution > 25 kW	457,127	$ 2.60	$ 1,188,529.50
	PPCA			$ (183,921.80)
Sub-total demand charge				$ 1,004,607.70
	Franchise Taxes	163,992,764	$ 0.0006	$ 101,675.51
	Demand Response Charges	93,147,348	$ 0.0007385	$ 68,789.32
	Total Billings			$ 3,168,808.59
	Per Bill Frequency Reports			$ 2,713,519.61
	Difference			$ (455,288.98)
	Percentage Difference			-16.78%

Causes of Revenue Variations

- Lack of pro forma adjustments in the cost of service study
- Pro forma adjustments are necessary to accurately reflect the cost of providing service when the rates will be in effect (the future)
- If you don’t include changes in the cost of service study, you won’t recover the changed costs later in rates

Pro Forma Example

Total Operating Expenses -- Less Purchased Power	$5,920,325
Pro-Forma Adjustments:	
Transmission & Substation Purchased Power Expense	$2,367,616
Production Demand Purchased Power Expense	$6,342,188
Purchased Power Energy Expense	$16,633,367
Labor Adjustment	$136,234
Depreciation Expense	$492,125
Total Pro-forma Operating Expenses	$31,891,854

Pro Forma Example

Total Operating Expenses Less Purchased Power	$3,135,777
Pro-Forma Purchased Power Adjustments:	
Demand	$1,752,107
Transmission Demand	$2,848,166
Energy	$9,659,335
Total Purchased Power Costs	$14,259,608
Labor Increase of 4%	$32,447
Increase in Pension Plan Costs	$63,600
Increase in O&M Expenses	$253,300
Depreciation Expense for Distribution Plant Increases	$17,802
Depreciation Expense for General Plant Increases	$9,666
Depreciation Expense for AMR	$36,733
Non-Purchased Power Operating Expense Pro Formas	$413,548
Total Pro-forma Operating Expenses	$17,808,933

Causes of Revenue Variations

- “Variabilizing” fixed costs combined with sales reductions
- A bedrock principle of ratemaking is to recover fixed costs through fixed charges and variable costs through variable charges
- Intra-class subsidies result if this principle is not followed
- It also puts fixed cost recovery at risk

“Variabilizing” Fixed Costs

- Distribution demand costs recovered through kWh charge
- G&T demand charges in base rates recovered on a kWh basis
- Power cost adjustment to recover changes in G&T demand charges assessed on a kWh basis (also causes “drift” in class rates of return over time)

Two-Part Rate Design

Cost of Service		**Rate Design**
Energy Costs ($ per kWh)	→	Energy Charge
Demand Costs ($ per kWh)	→	Energy Charge
Customer Costs ($ per Customer)	→	Customer Charge

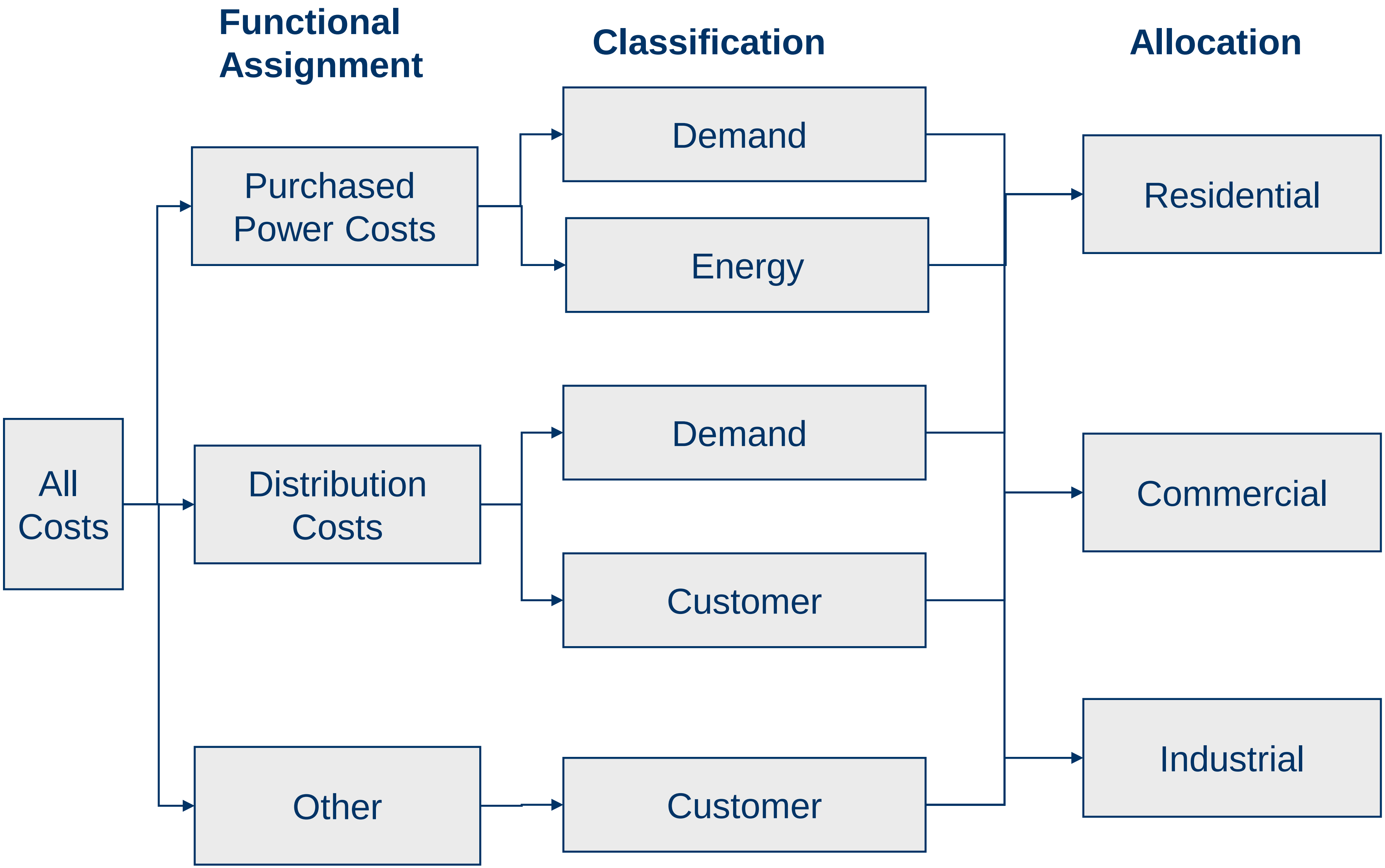
Three-Part Rate Design

Cost of Service	**Rate Design**
Energy Costs ($ per kWh)	Energy Charge
Demand Costs ($ per kW)	Demand Charge
Customer Costs ($ per Customer)	Customer Charge

Residential Rate Example

- Proposed Delmarva rates in Delaware Docket No. 09-414
- Customer Charge of $17.04 per customer per month
- Distribution Demand Charge of $4.33144 per kW-month
- This is probably the beginning of a trend in the industry

Cost of Service Study



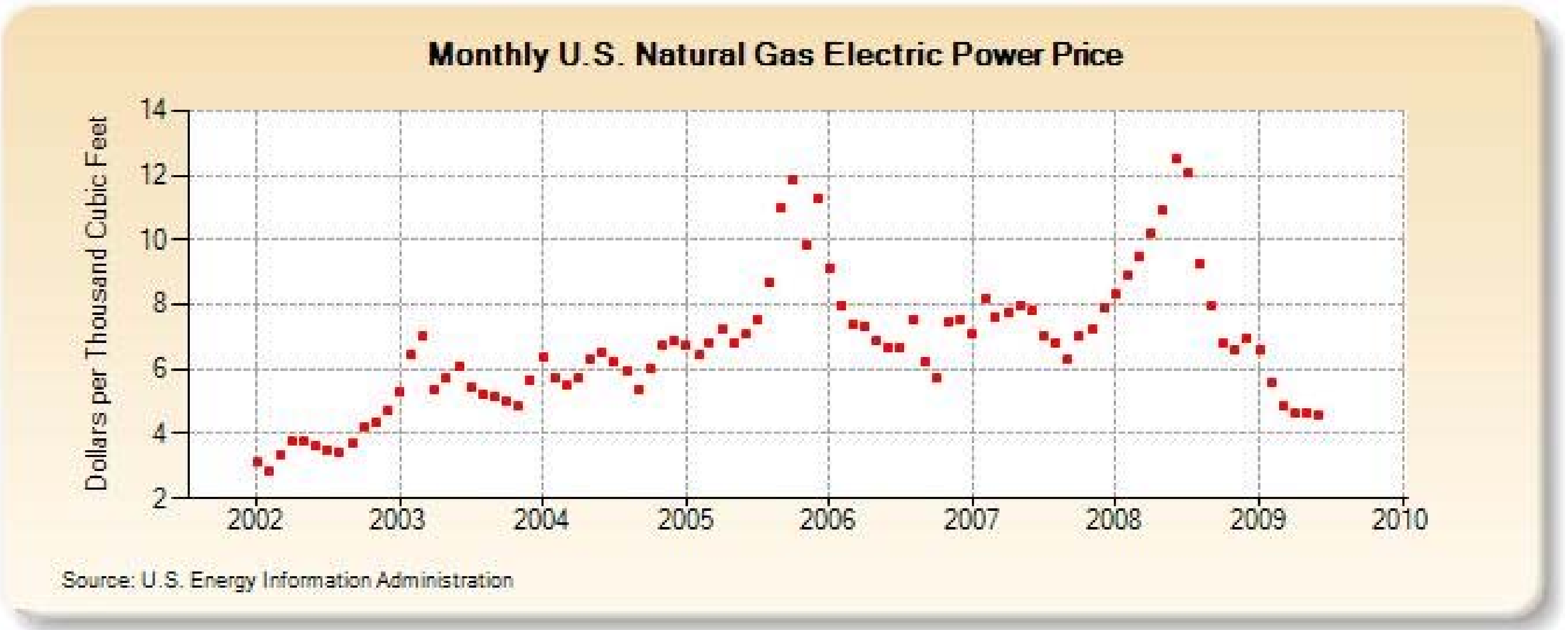
Causes of Revenue Variations

- No power cost adjustment when purchased power costs are increasing
- Purchased power costs are likely to increase due to a number of factors

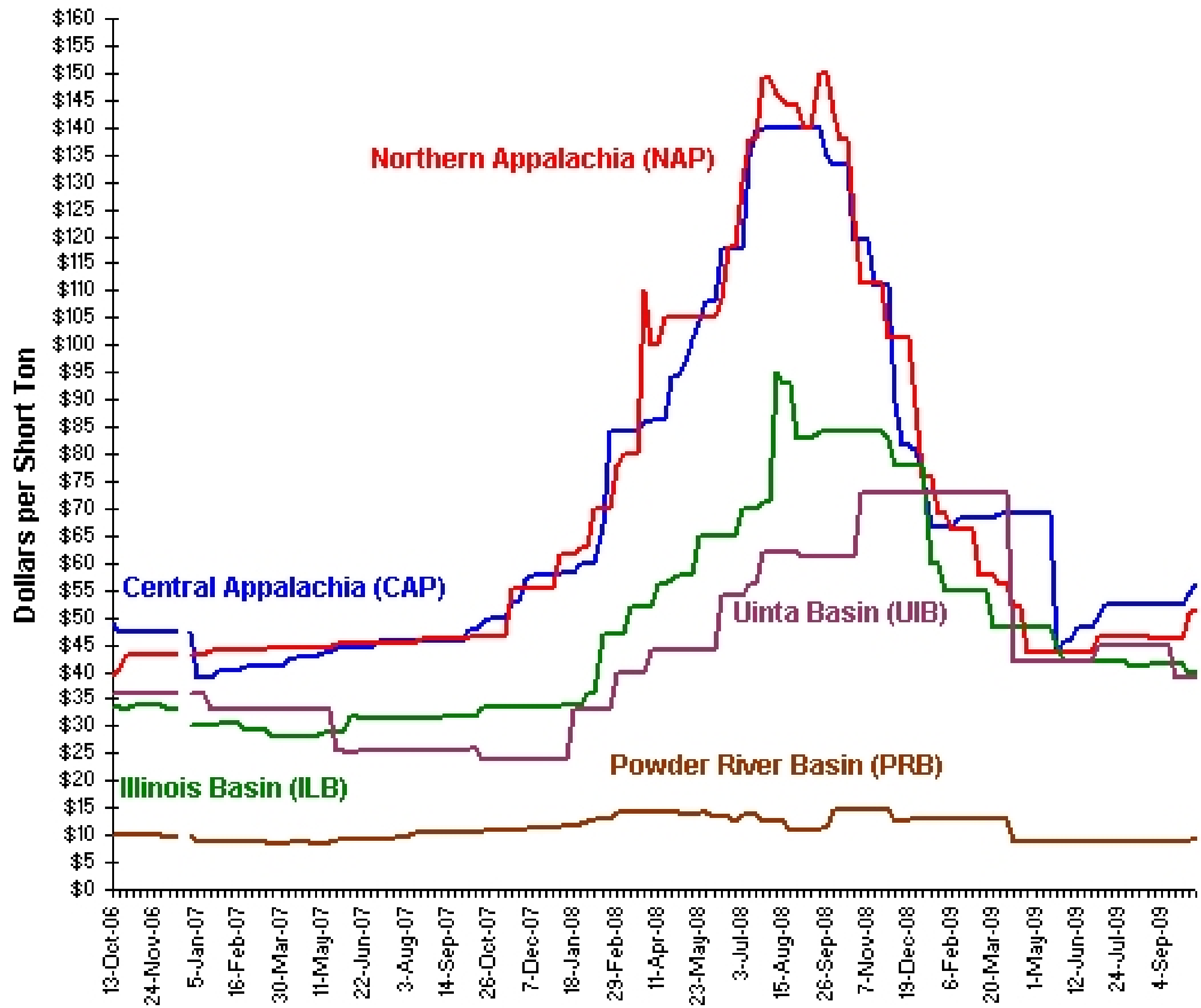
Factors Affecting Electric Rates

- A perfect storm for wholesale price increases
- Generation plant cost increases
  - Increased about 124% in since January 2000 according to IHS CERA Power Capital Costs Index
- Fuel price increases and volatility

U.S. Natural Gas Prices for Use in Electric Power Production



Coal Prices



Key to Coal Commodities by Region

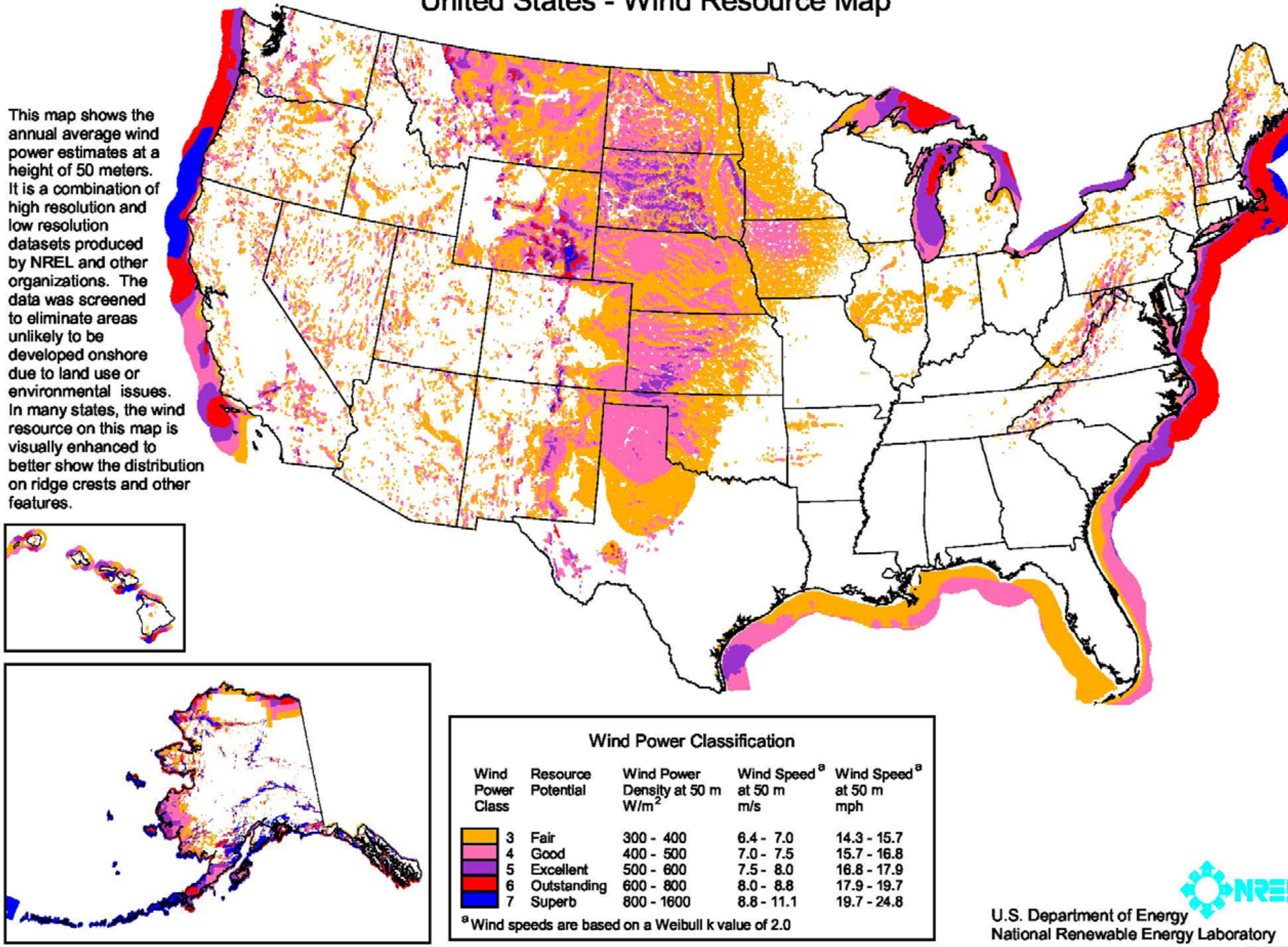
Central Appalachia:	Big Sandy/Kanawha 12,500 Btu, 1.2 lbSO2/mmBtu	Powder River Basin:	8,800 Btu, 0.8 lb SO2/mmBtu
Northern Appalachia:	Pittsburgh Seam 13,000 Btu, <3.0 lbSO2/mmBtu	Uinta Basin in Colo.:	11,700 Btu, 0.8 lb SO2/mmBtu
Illinois Basin:	11,800 Btu, 5.0 lb SO2/mmBtu		

Factors Affecting Electric Rates

- Cost of renewable portfolio standard (RPS)
  - Generation cost from renewables
  - Intermittent nature of renewables and the necessary regulation service for these facilities
  - Location of renewables - new transmission to move power from renewable generators

United States - Wind Resource Map

This map shows the annual average wind power estimates at a height of 50 meters. It is a combination of high resolution and low resolution datasets produced by NREL and other organizations. The data was screened to eliminate areas unlikely to be developed onshore due to land use or environmental issues. In many states, the wind resource on this map is visually enhanced to better show the distribution on ridge crests and other features.



Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m^2	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

[a] Wind speeds are based on a Weibull k value of 2.0

NREL
U.S. Department of Energy
National Renewable Energy Laboratory
06-MAY-2009 1.1.9

Cost of Transmission

- Cost per mile of line
  - 765 KV - $2,600,000 per mile
  - 345 KV - $1,500,000 per mile
  - 138 KV - $ 250,000 per mile
  - 69 KV - $ 150,000 per mile

Factors Affecting Electric Rates

- Environmental concerns
  - Sulfur dioxide
  - Nitrogen oxide
  - Mercury
  - Carbon dioxide
  - Restrictions on once through cooling

Carbon Regulation

- EPA has issued a proposed rule that would regulate green house gas emissions from large stationary sources
- Would regulate carbon emissions under the Clean Air Act
- This could be very expensive for utilities with significant amounts of coal generation

Carbon Cost Impacts

- In the Midwest, each $10 per ton of carbon emissions cost would increase the price by about 1 cent per kWh
- There would be no additional energy provided by this cost increase

Power Cost Adjustments

- Many cooperatives eliminated power cost adjustments when G&T wholesale rates were falling
- Resulted in increased margins without raising rates
- Necessary when wholesale power costs are increasing

Causes of Revenue Variations

- Weather
  - A few hot days with the rest of the month mild
  - Reduces customer load factors and increases delivered cost per kWh
  - Compare current HDD and CDD to test year HDD and CDD
  - Compare current usage to weather normalized usage

Causes of Revenue Variations

- Power Cost Adjustment lag
  - Hot or cold weather with a lag in recovering purchased power costs through a purchased power cost adjustment (annual changes, rolling average)
  - Mainly a timing issue

Causes of Revenue Variations

- Economic recession resulted in decreased usage by customers
- Analysis by class
  - Residential - vacant homes and psychological impacts
  - Reductions for commercial and industrial classes
- A timing issue that may end as the recession ends

Causes of Revenue Variations

- Optional time of use rates
  - Could be partially or completely offset by cost reductions
  - Could be natural winners under TOU which eliminates subsidy that these customers have paid historically
  - Rates are averages and TOU may appeal to and remove from the rate customers with a below average cost of service
  - Leads to rate increase for remaining customers in the future

Protecting Revenue

- Collect fixed costs through fixed charges
  - Customer charge
    - All customer related costs
    - Customer related costs plus all margins
    - All distribution costs and margins (straight fixed variable rate design)
  - Distribution demand charge collected through NCP demand charge
  - G&T demand charge collected through CP or NCP demand charge (match G&T billing determinants)

Protecting Revenue

- Demand ratchets
  - May harm efforts to drive costs out of the business
- Expense trackers

Questions?

- Eric Blake

  - The Prime Group, LLC
  - P.O. Box 837
  - Crestwood KY 40014
  - 502-241-4405
  - eablake@insightbb.com