



Your Trusted Energy Advisor

Independent Power Producer View
**Minimizing Costs and
Maximizing Value for
Compression Facilities**

Gas/Electric Partnership

Managing Today's Challenges in Gas Compression

Dallas Special Workshop

September 9, 2010



Discussion Topics

- PPM Overview
- Market Review
- Minimizing Costs
- Maximizing Value

Priority Power Management LLC

- Independent and unbiased energy management and consulting services firm established in January 2001;
- Midland/Odessa, Dallas/Fort Worth, Houston, Atlanta;
- Extensive energy experience:
 - *25 employees, key management combines for 250+ years of energy experience*
 - *1,200+ clients, approximately 12,000 accounts under management*
 - *Over 1,300MW of NCP peak power demand under management*
 - *8.1 TWh of power managed annually, enough to power 340,000+ homes/yr*
 - *40 Bcf of physical and financial natural gas positions managed annually*
 - *\$1 billion of annual energy spend under management*
- One of the largest commercial energy buyers in Texas;
- Licensed Aggregator by the Public Utility Commission of Texas (Lic. No. 80011).

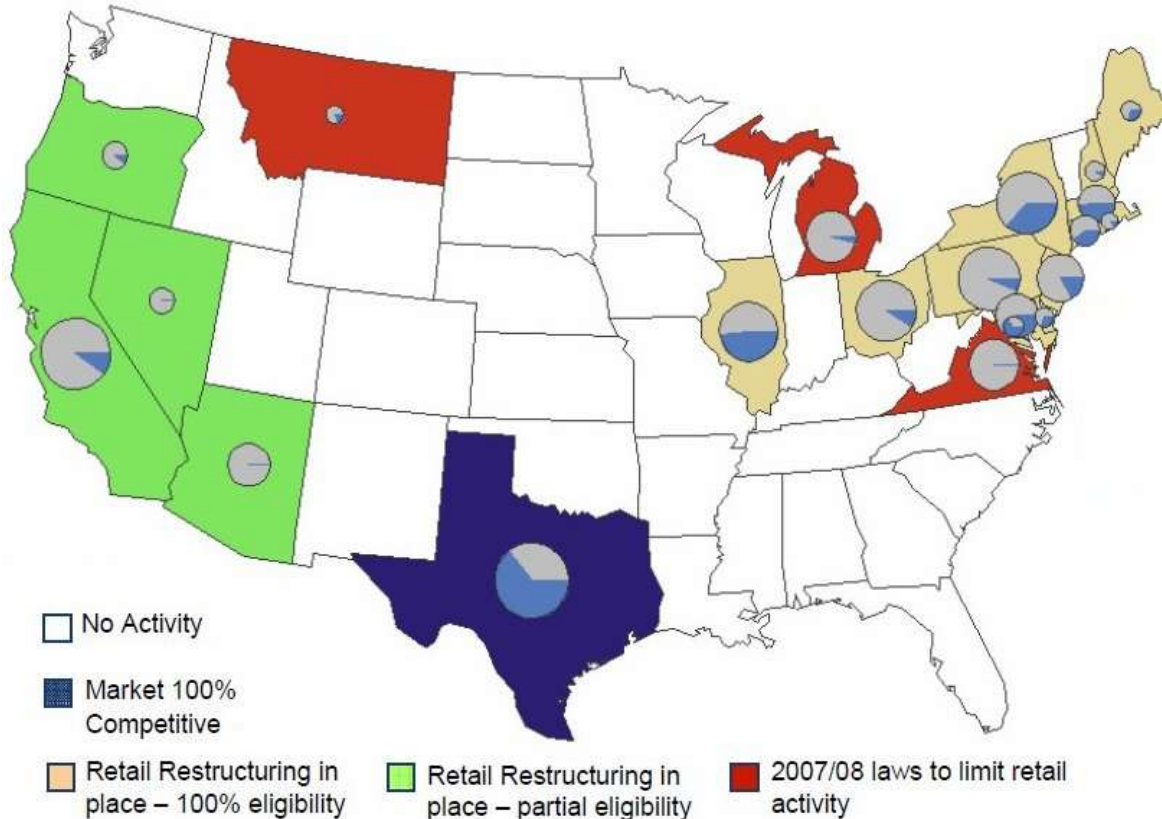
Strong Energy Experience

A third of the Top 100 oil and gas producers in Texas, and leading midstream and long-haul pipeline companies have relied on Priority Power Management to manage their power requirements.



State of US Retail Electric Markets

Most markets are vigorous and growing. Low prices, rate cap extensions and incremental improvements in policy have advanced retail electricity markets.

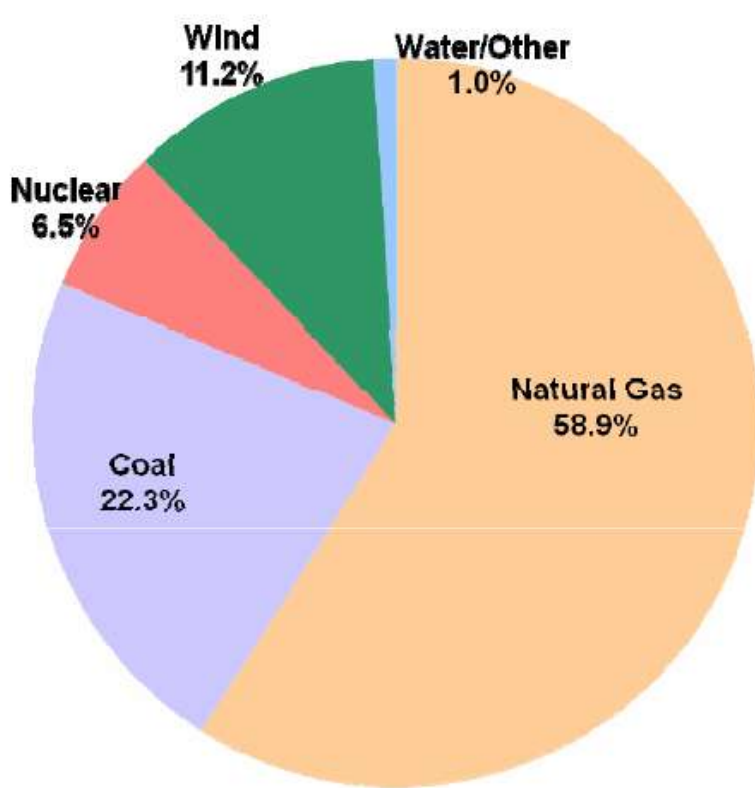


- No new markets opening
- No markets reregulating
- Policy climate improving
- Recession and MI re-reg drove -9% decline in eligible volumes, yet competitive market grew
- OH largest growth market in '09 and PA to be the largest in '10/'11
- EE/DR/DG/SG are fueling change in retail power markets
- Retailer earnings are strong.

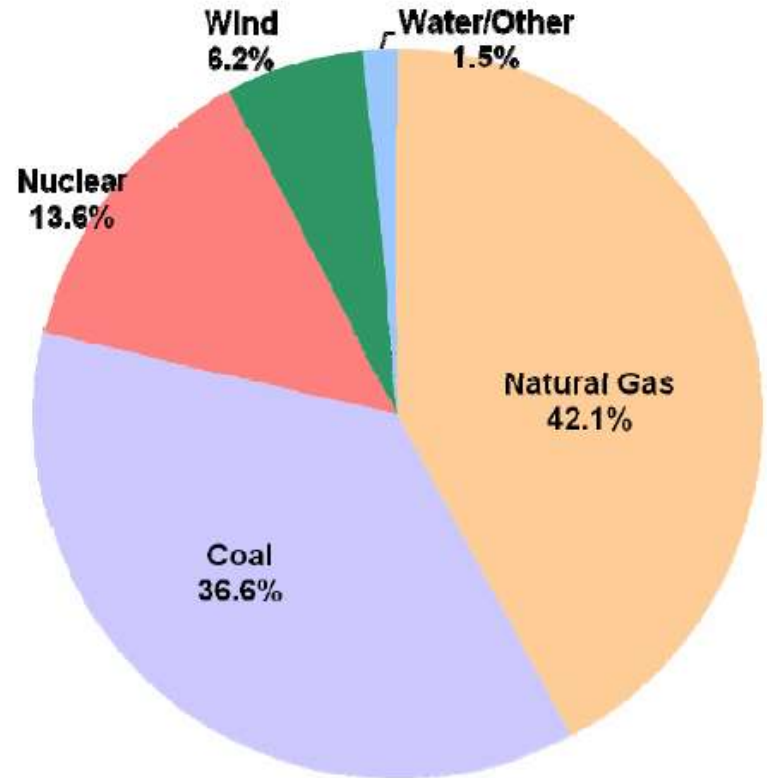
Status Pie Charts = size of eligible and % switched market

ERCOT Capacity and Energy by Fuel Type

ERCOT has the highest dependency on natural gas of any other region, making it more vulnerable to supply disruptions and price volatility.



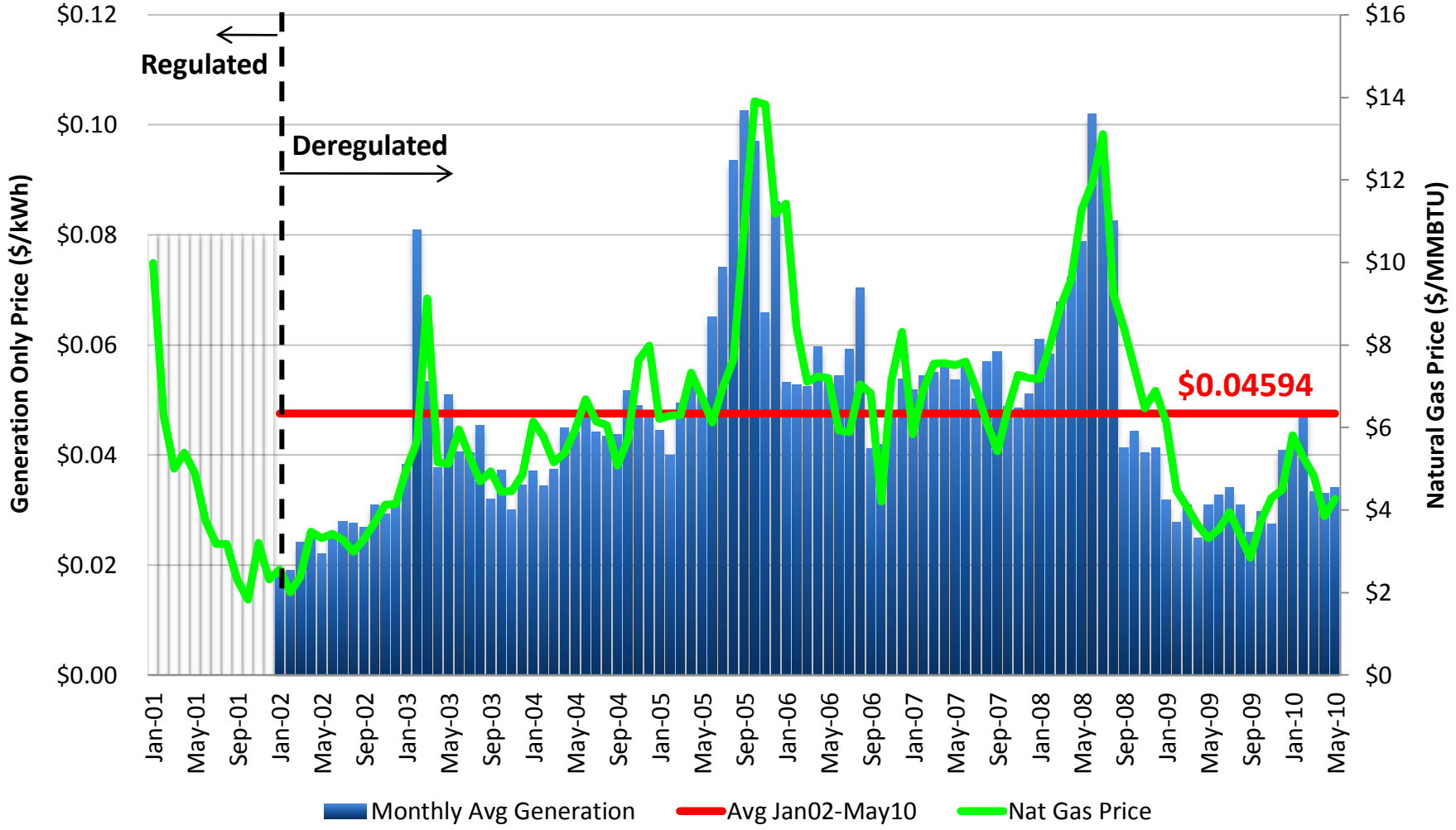
Installed Capacity by Fuel Type, 2009



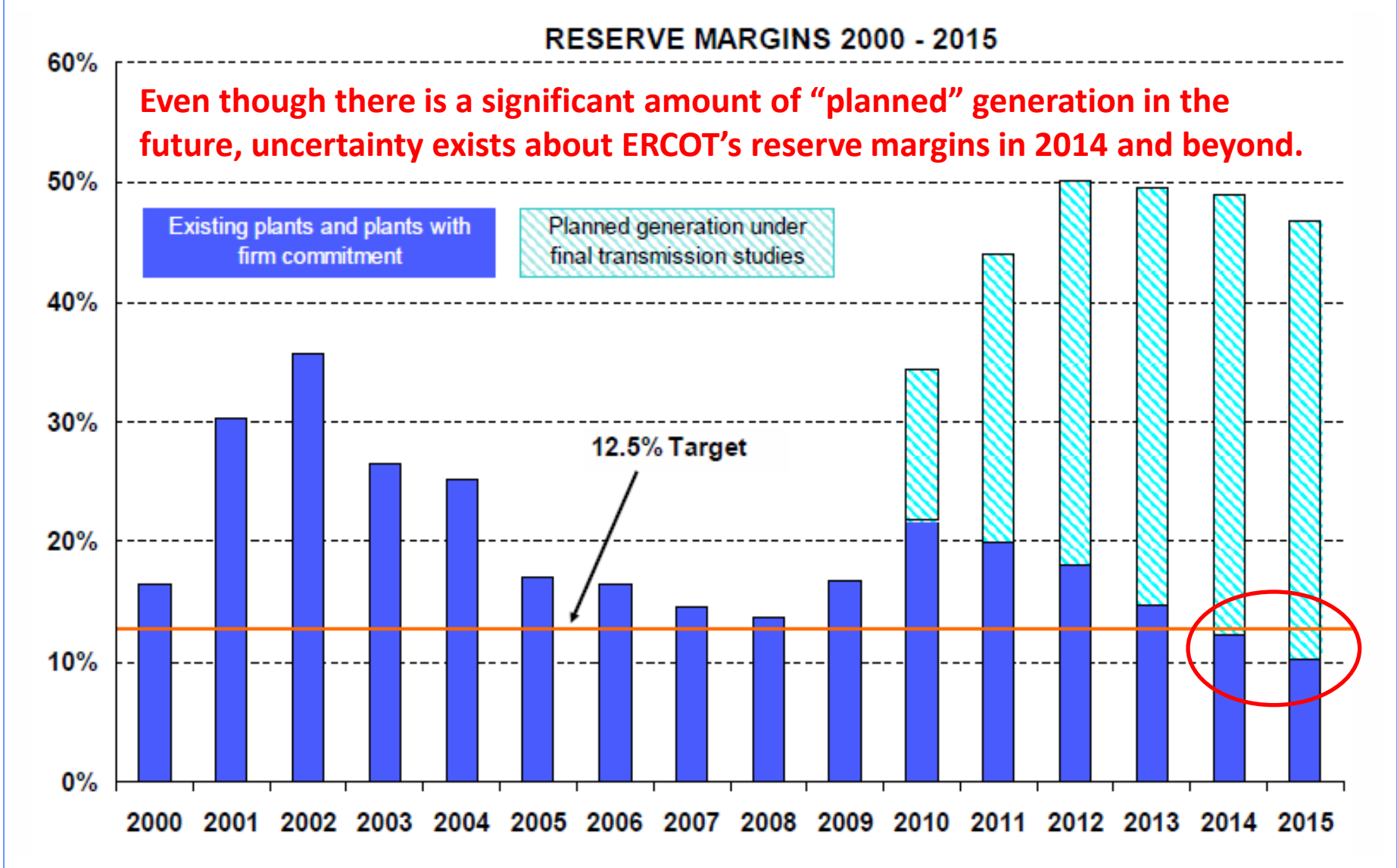
Energy by Fuel Type, 2009

ERCOT Power vs Gas

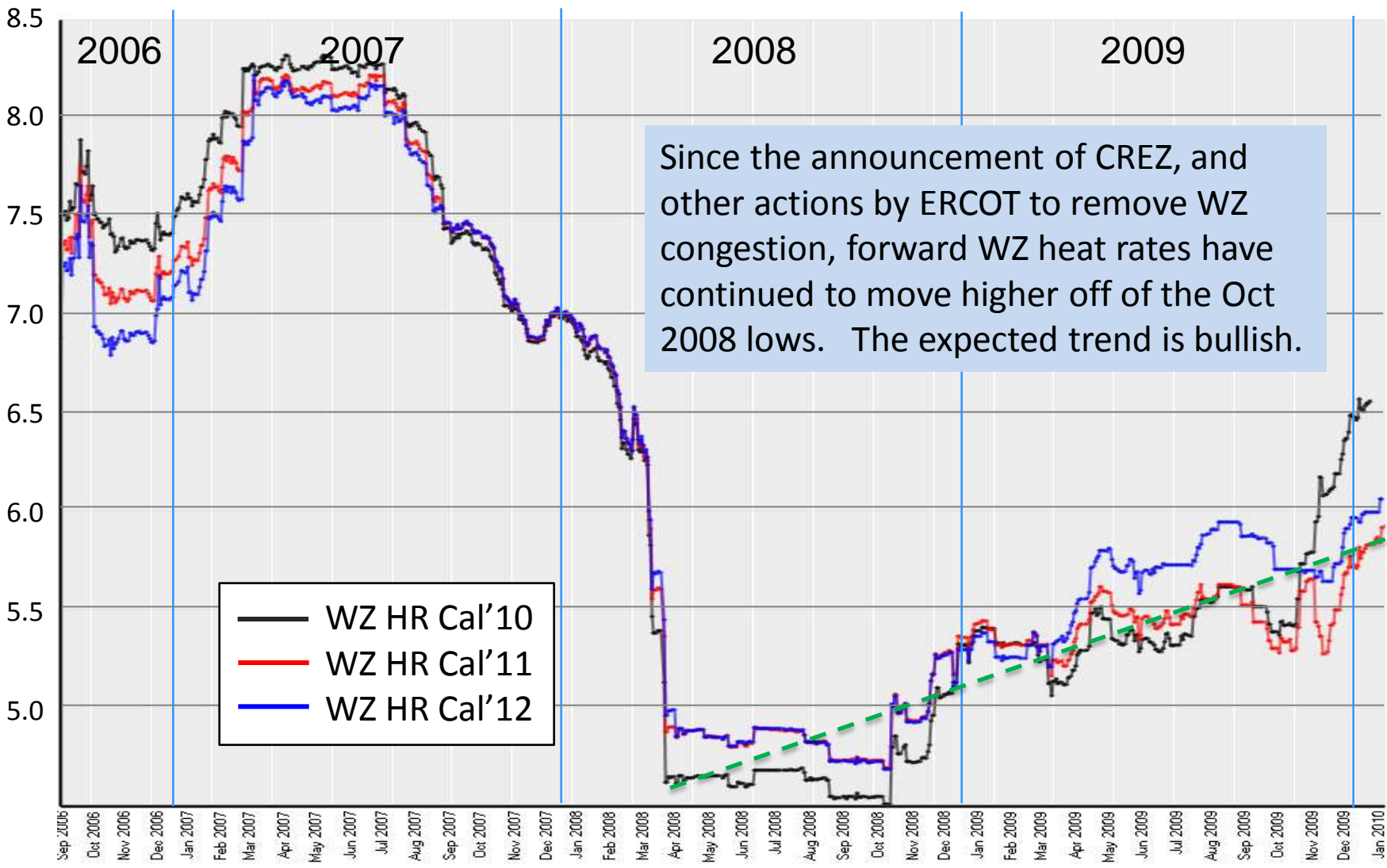
Natural Gas Prices are the Primary Driver of the trends in electricity prices.



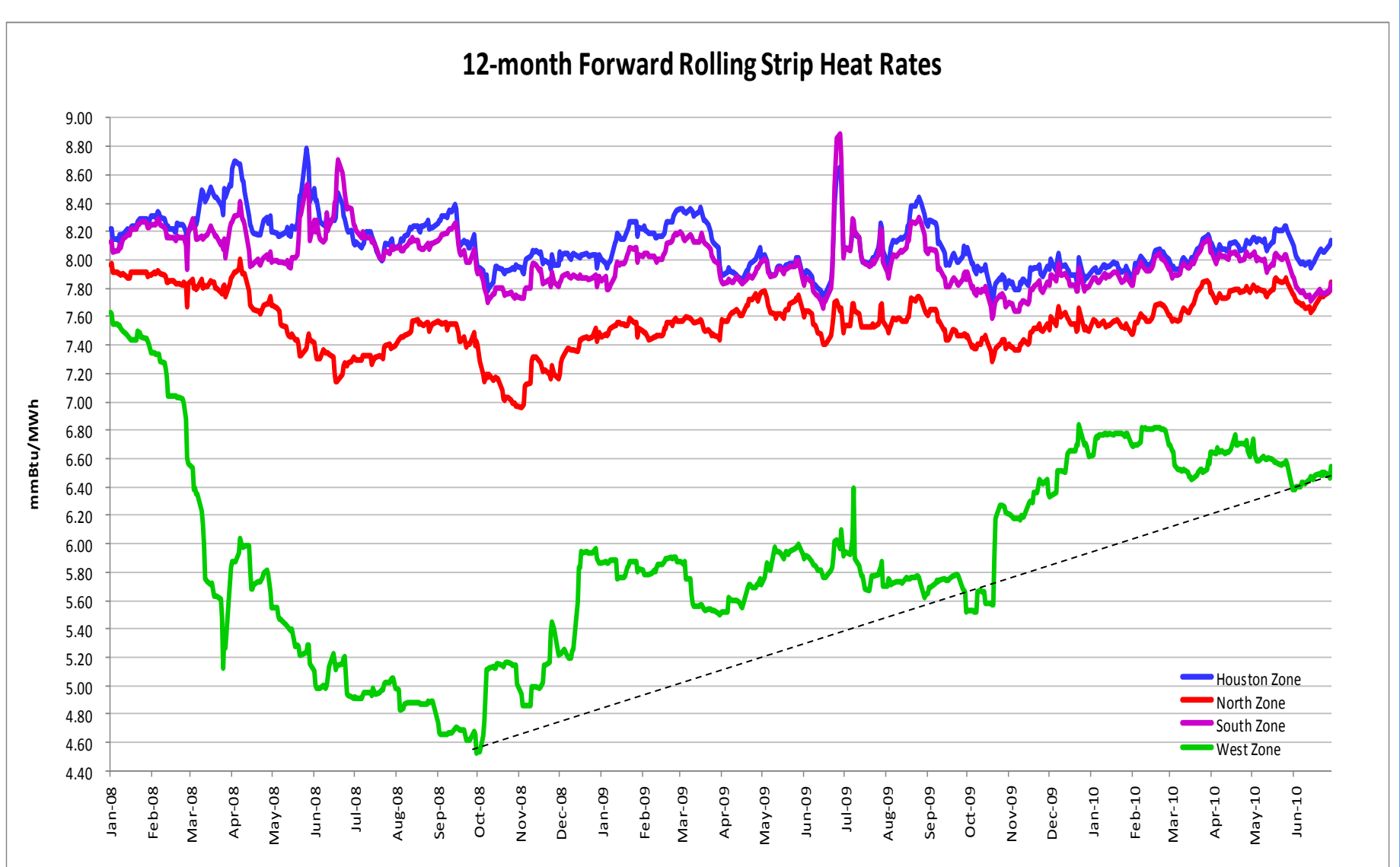
ERCOT Reserve Margins



WZ HR Trends

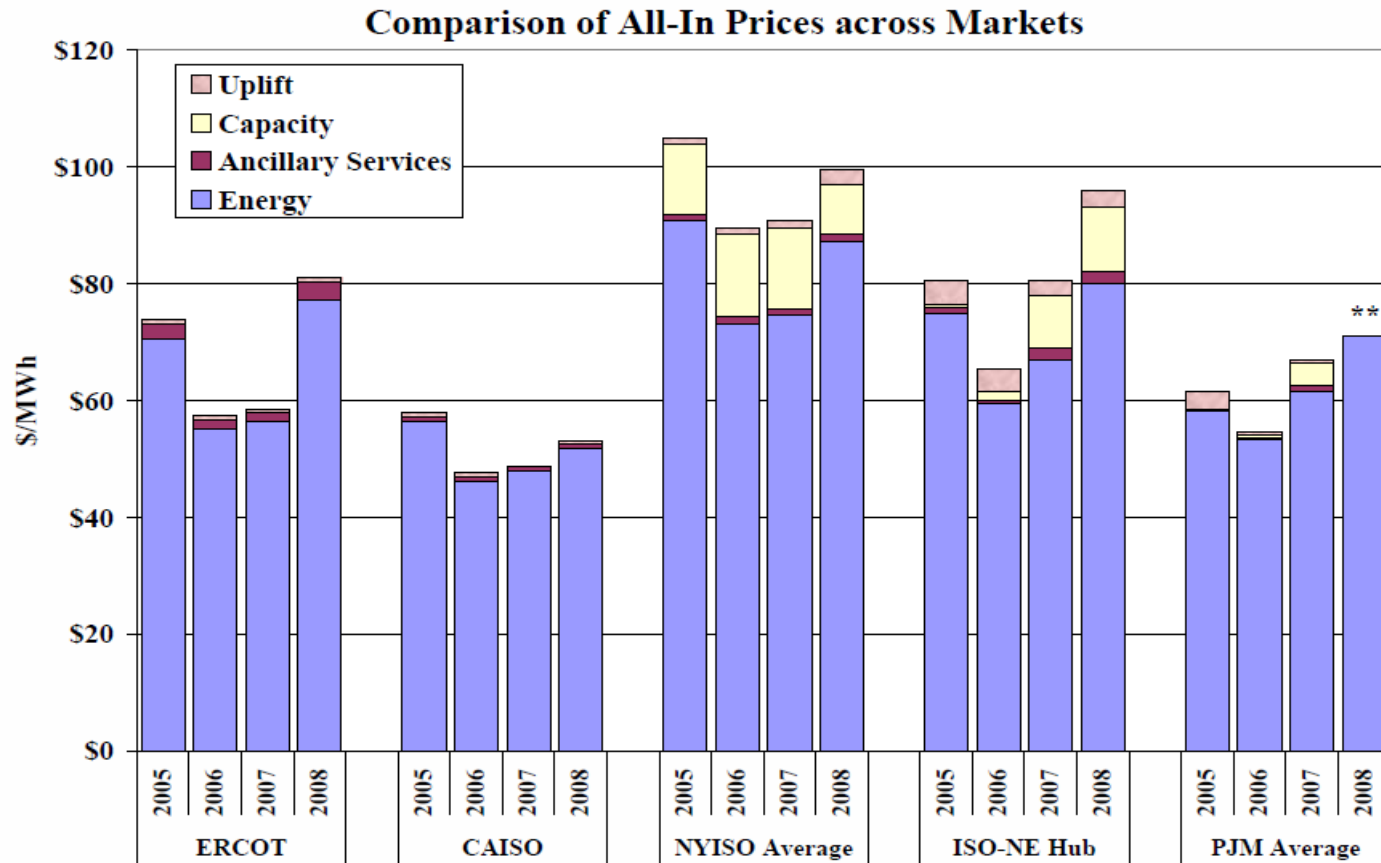


12-Month Forward Strip Heat Rates



ERCOT vs. Other Markets

The following figure compares the all-in prices in ERCOT with other organized electricity markets in the U.S.: California ISO, New York ISO, ISO New England, and PJM. For each region, the figure reports the average cost (per MWh of load) for energy, ancillary services (reserves and regulation), capacity markets (if applicable), and uplift for economically out-of-merit resources.



** 2008 Capacity, Ancillary Services and Uplift data unavailable for PJM

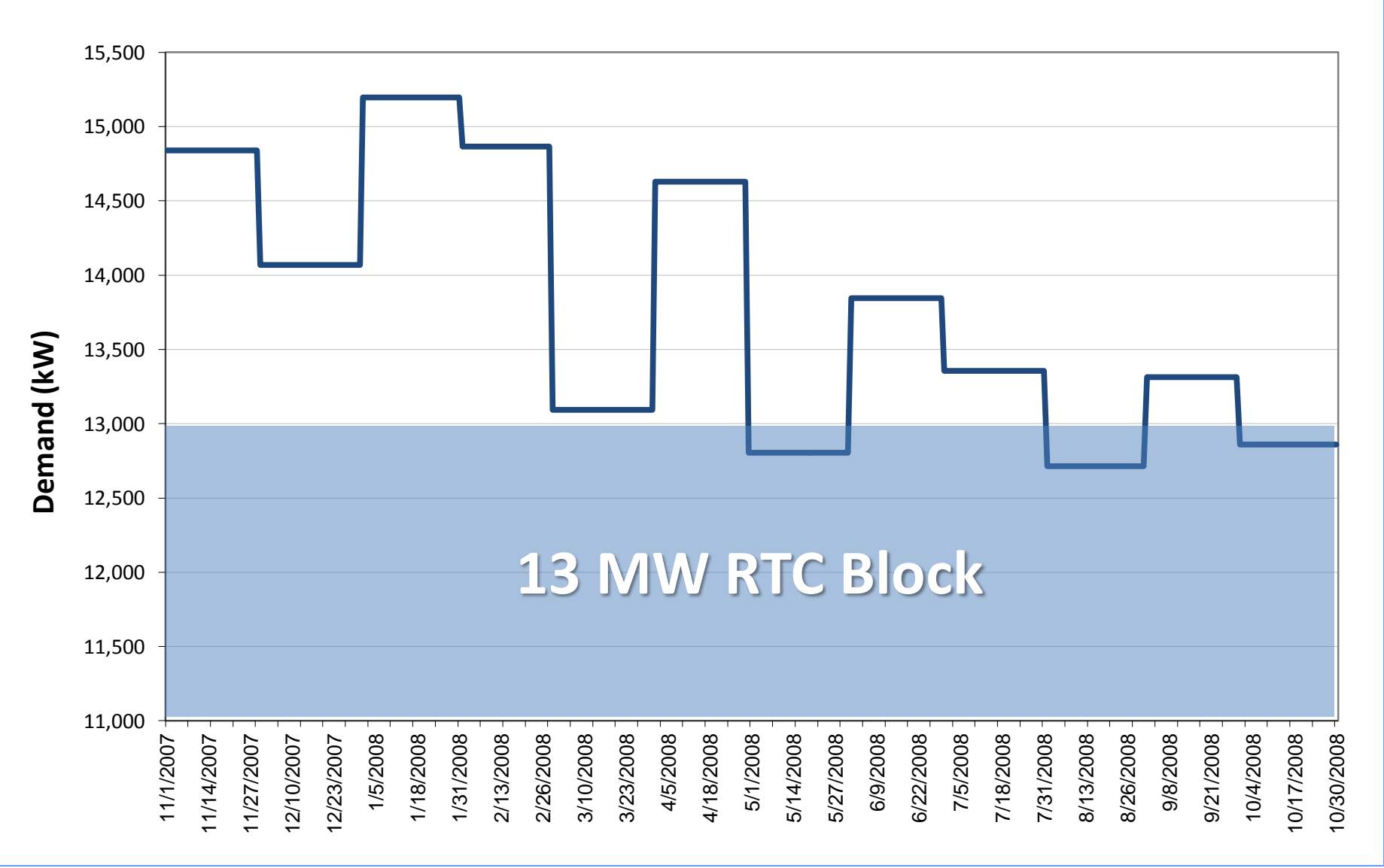
Minimizing Costs

- Establish a competitive sourcing process;
- Understand your current and future load requirements;
- Determine your risk tolerance and financial goals;
- Pick the right structure;
- Evaluate cost components separately;
- Actively manage hedge positions.

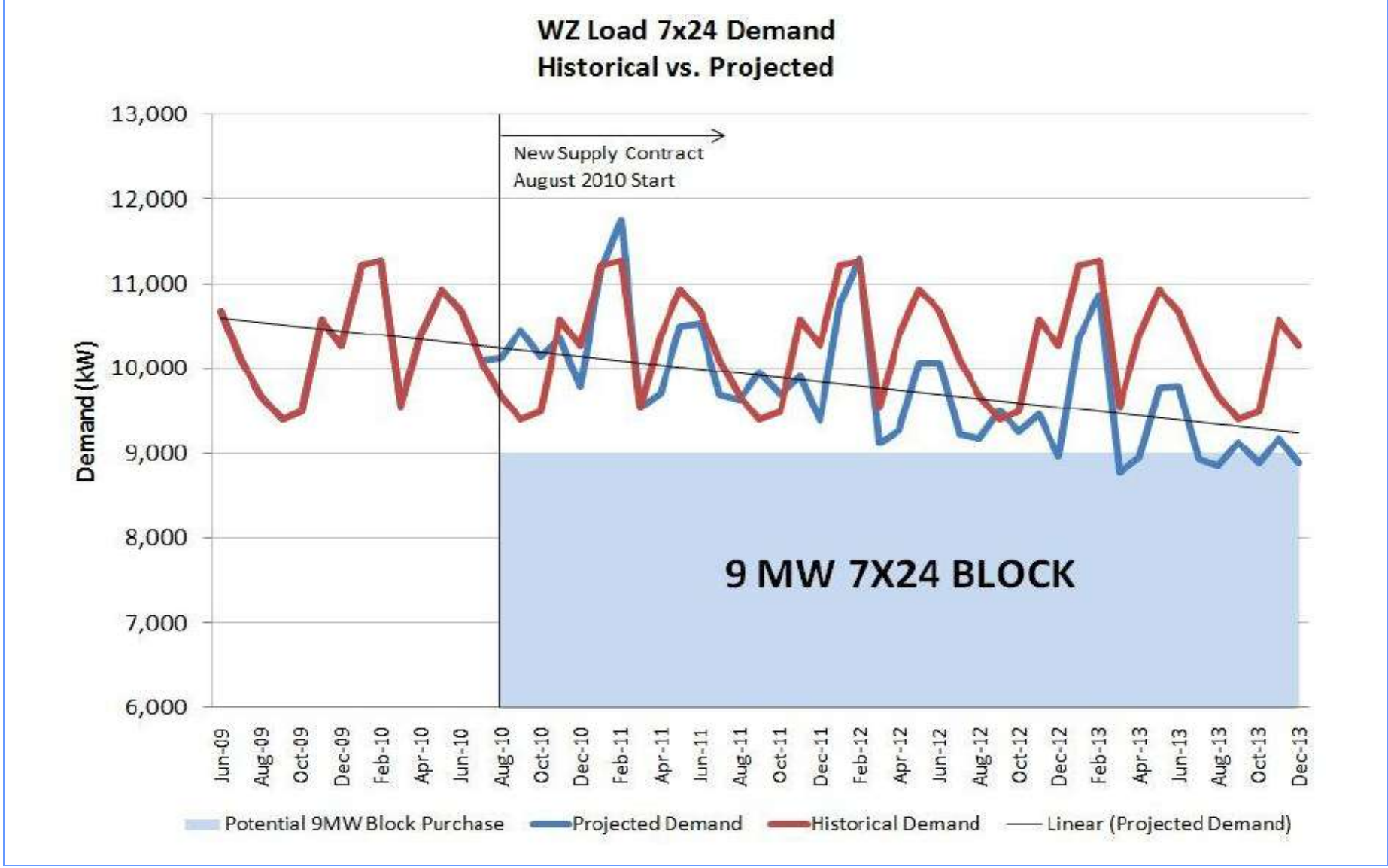
Establish a Process



Understand Your Load Shape



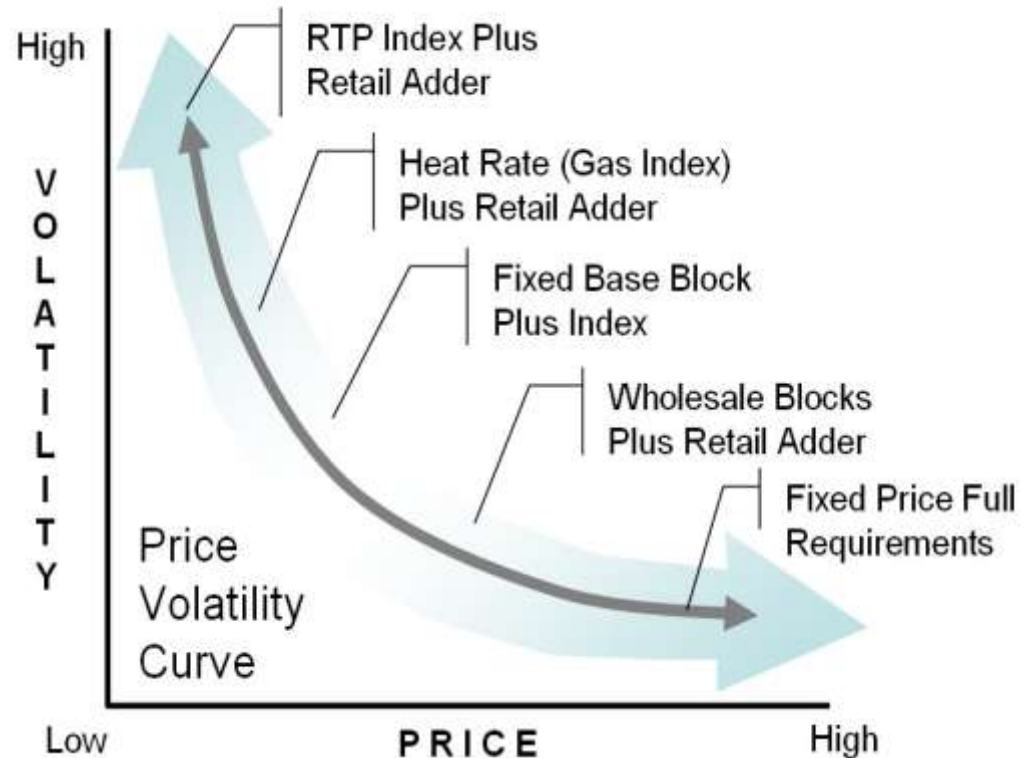
Anticipate Your Future Needs



Determine Your Risk Tolerance

- Fixed Price
 - Locks in ancillary, capacity & fuel components
- Heat Rate
 - Locks in ancillary & capacity, floats fuel costs
- MCPE
 - Locks in ancillary, floats capacity and fuel costs
- Others

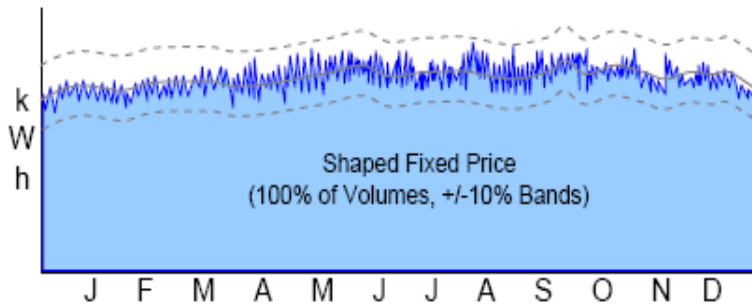
Price vs. Risk Continuum



Pick the Right Price Structure

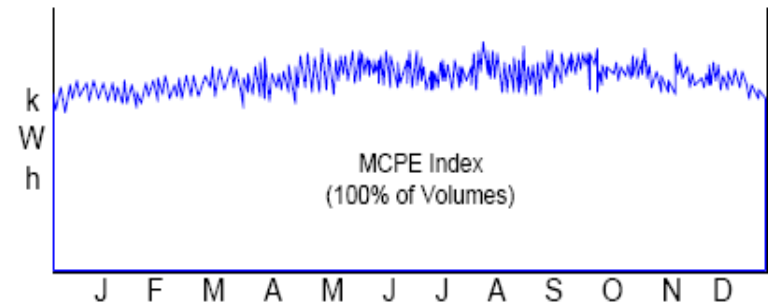
Evaluate various price structure options in an effort to determine the best fit for your specific financial / budget goals and risk tolerance.

Structure 1: Fixed Price



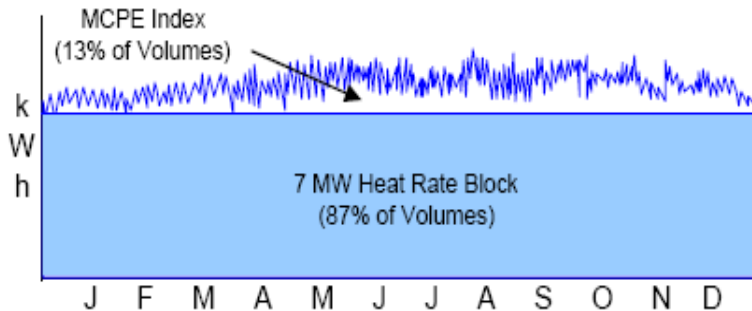
LOW RISK

Structure 2: MCPE + Retail Adder



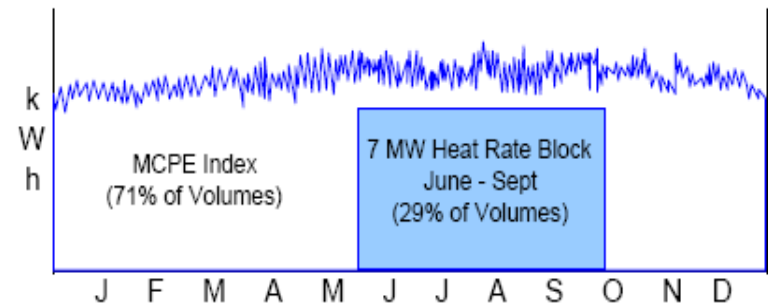
HIGH RISK

Structure 3: Heat Rate Block + MCPE + Retail Adder



AVERAGE RISK

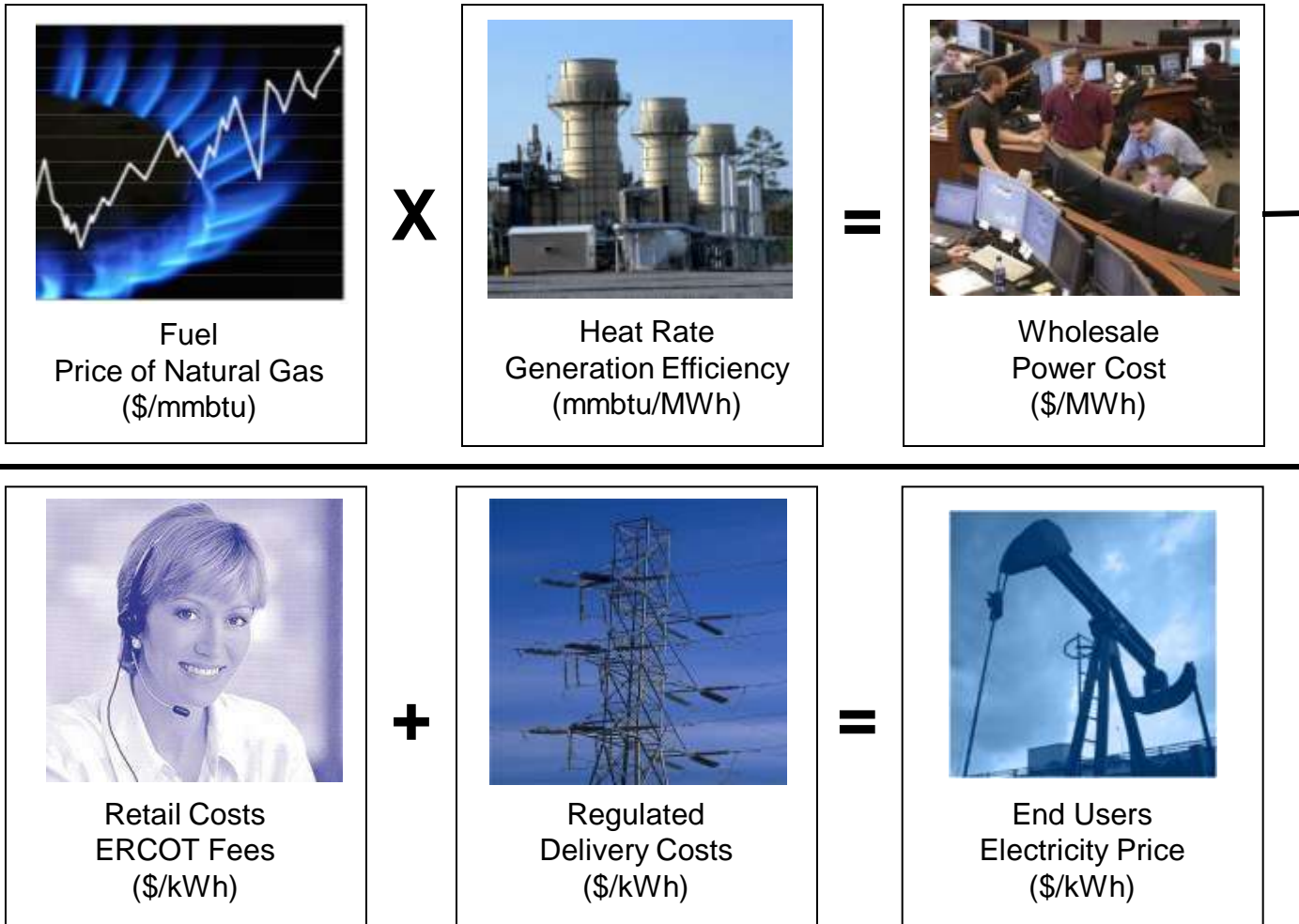
Structure 4: Seasonal Heat Rate Block + MCPE + Retail Adder



AVERAGE RISK

Evaluate Cost Components Separately

Unbundling electricity cost components to manage them independently, generally results in lower overall cost and managed risk.



Heat Rate Products - A Natural Hedge

HR	x	Gas	=	Power	+	Adder	=	Cost
6.50	x	\$4.00	=	\$26.00	+	\$7.00	=	\$33.00
6.50	x	\$5.00	=	\$32.50	+	\$7.00	=	\$39.50
6.50	x	\$6.00	=	\$39.00	+	\$7.00	=	\$46.00
8.50	x	\$4.00	=	\$34.00	+	\$7.00	=	\$41.00
8.50	x	\$5.00	=	\$42.50	+	\$7.00	=	\$49.50
8.50	x	\$6.00	=	\$51.00	+	\$7.00	=	\$58.00

BUY FIXED **ACTIVELY MANAGE** **BUY FIXED**

Fuel Cost Comparison Analysis

Based on the use of a CAT 3612 in PJM market.

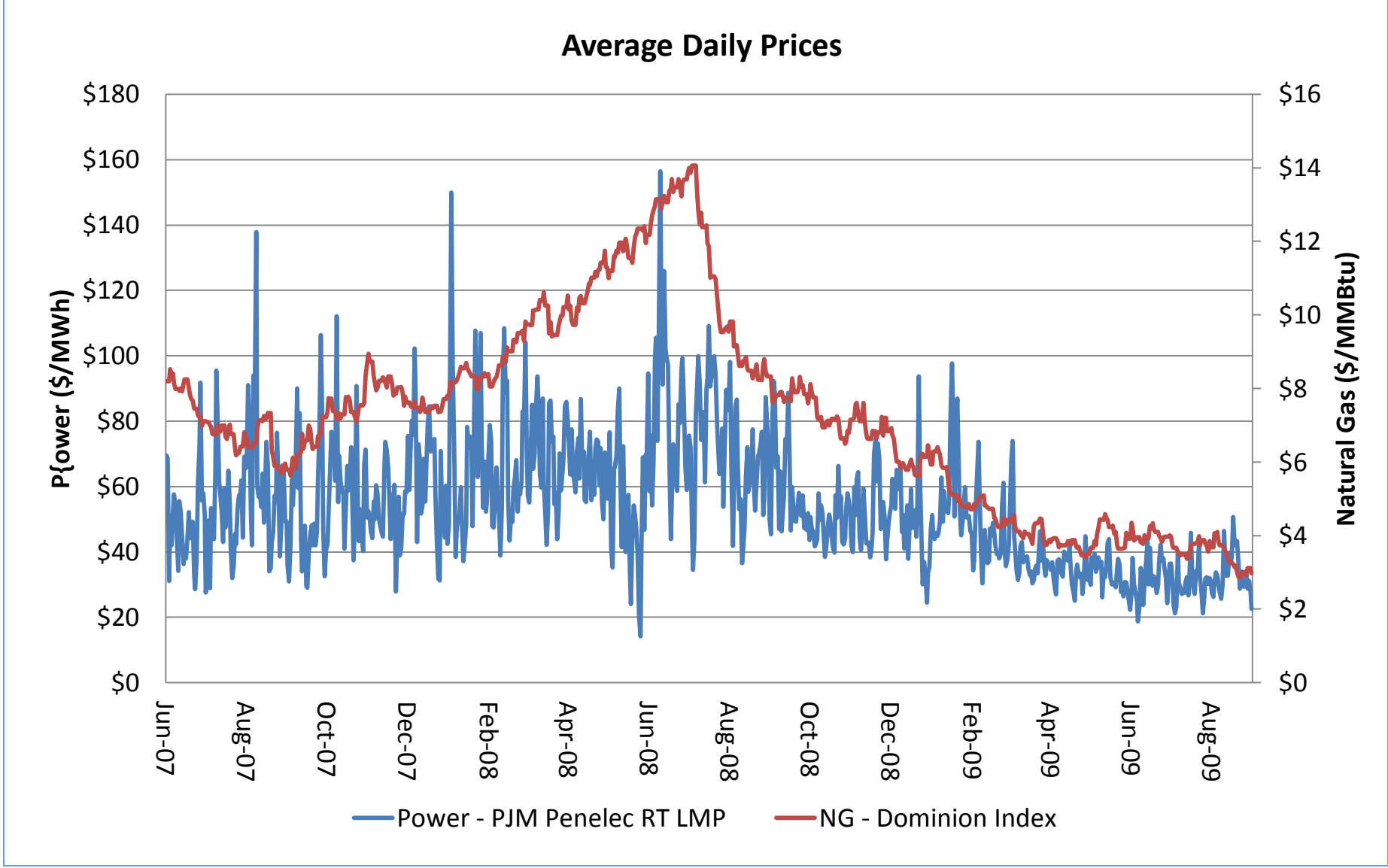
Historical Price Look Back

Reference Term		NG IFERC FOM DSP		Power All-In		NG vs Power Variance	
		\$/MMBtu	\$	\$/MWh	\$	\$	%
Start	Jun-07	\$7.22	\$3,790,471	\$72.95	\$3,807,992	-\$17,521	-0.5%
End	Aug-09						

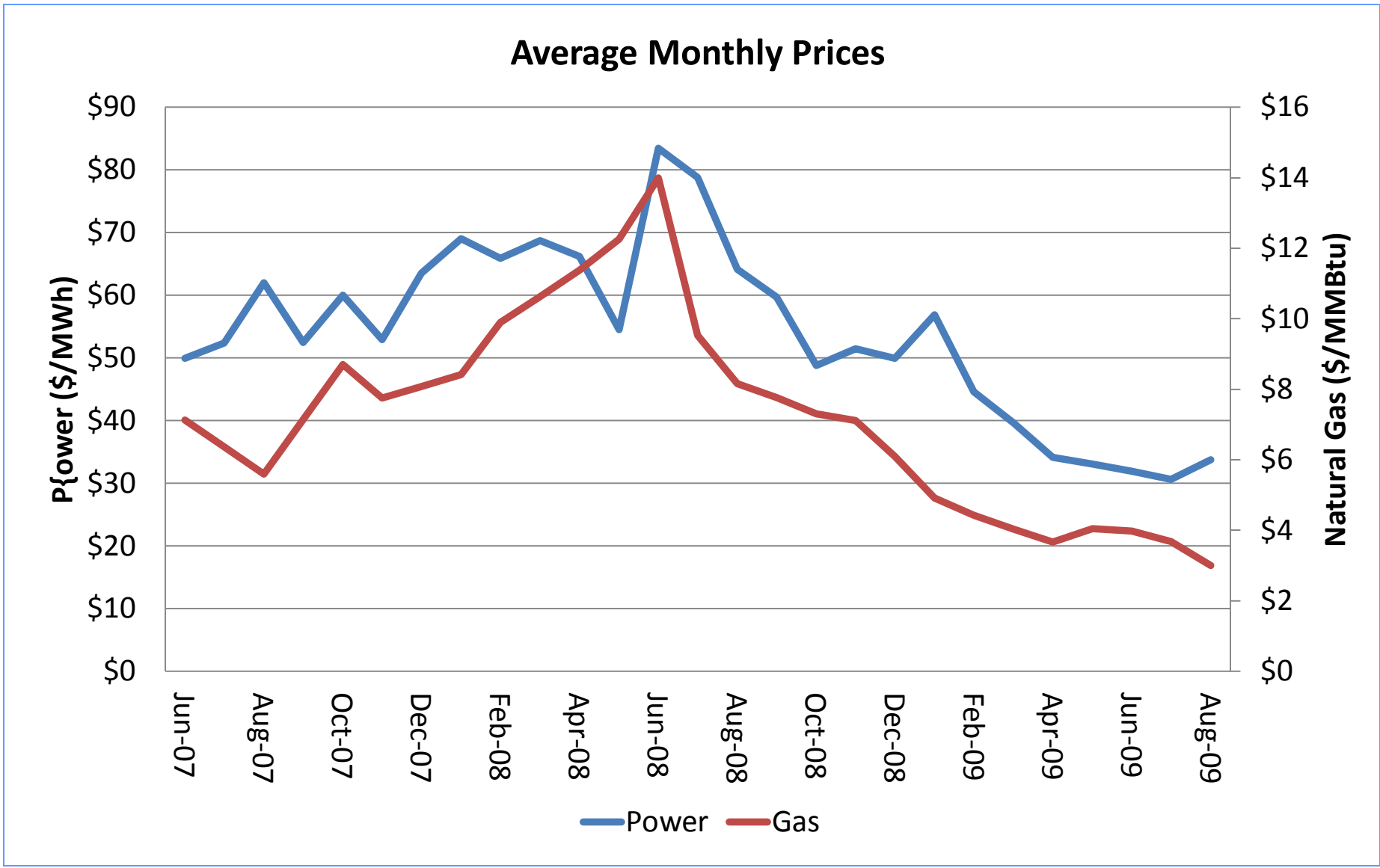
Indicative Forward Prices

Reference Term		NG GDD DSP		Power All-In		NG vs Power Variance	
		\$/MMBtu	\$	\$/MWh	\$	\$	%
Start	Jan-10	\$6.81	\$7,940,350	\$68.98	\$8,000,810	-\$60,460	-0.8%
End	Dec-14						

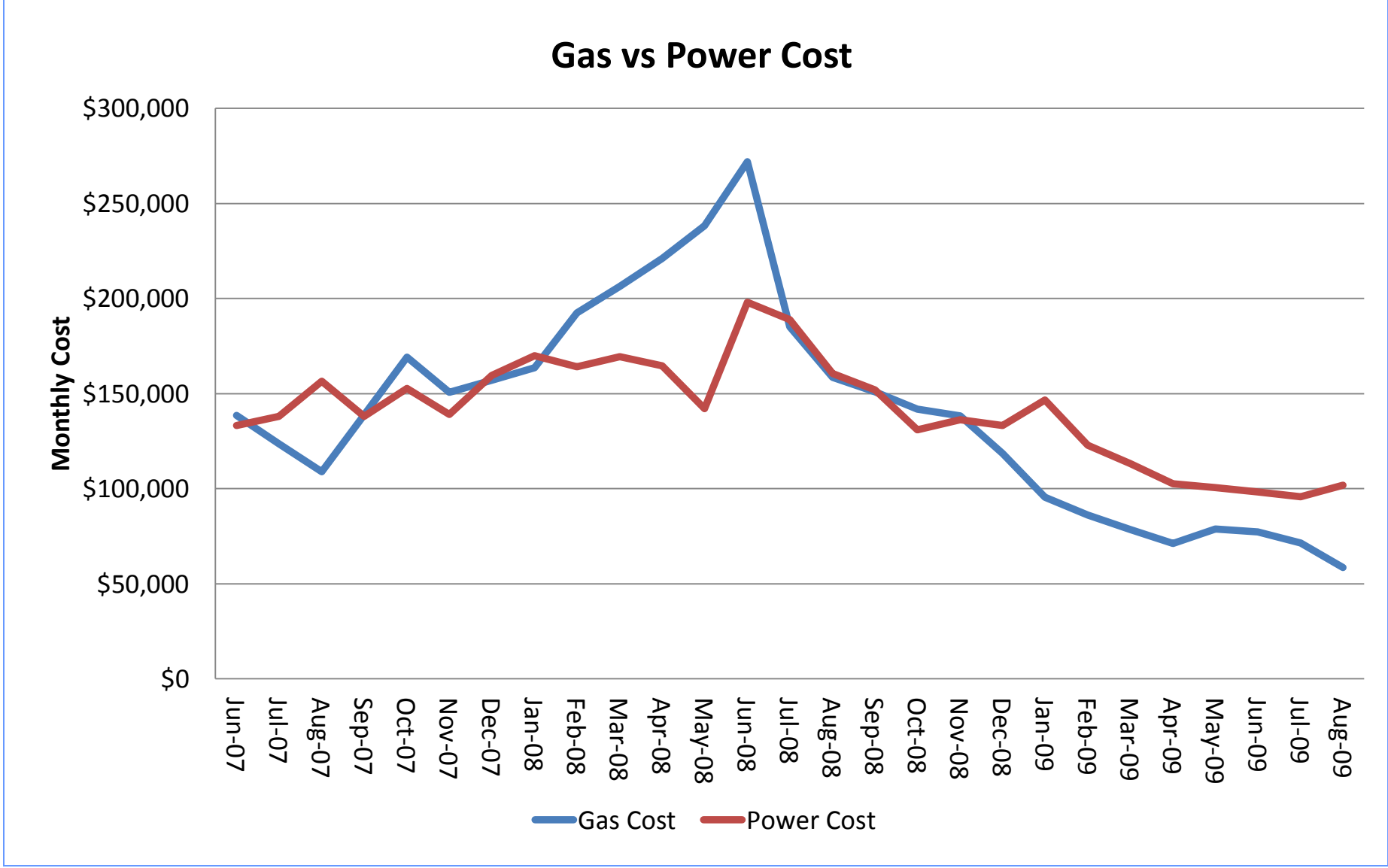
Power PJM Penelec RT LMP vs NG Dominion Index



Power PJM Penelec RT LMP vs NG Dominion Index



Cost Comparison



Consider Peak Demand Management

The ability to reduce an electric CF peak demand during periods that are coincidental to the grid’s peak demand will reduce regulated delivery costs;

Potential savings per kW of demand reduced during periods when ERCOT sets its peak demand, and are based on current tariffs as of 5/15/2010.

TDSP Provider	Secondary	Primary	Transmission
Oncor (kW)	\$26.04	\$25.20	\$24.72
Centerpoint (kVA)	\$22.76	\$23.54	\$22.67
AEP North (kW)	\$27.17	\$27.94	\$19.67
AEP South (kW)	\$25.16	\$29.18	\$25.60
TNMP	\$15.31	\$32.83	\$23.46

Assume CF is (1) on the Oncor system, (2) and receives electricity service at a “Primary” level, and (3) CF reduces coincidental peak demand by 5,000 kW.

The CF will have avoided TDSP transmission charges by \$126,000 ($\$25.20/\text{kW} \times 5,000 \text{ kW}$) for the following calendar year.

Maximize Value

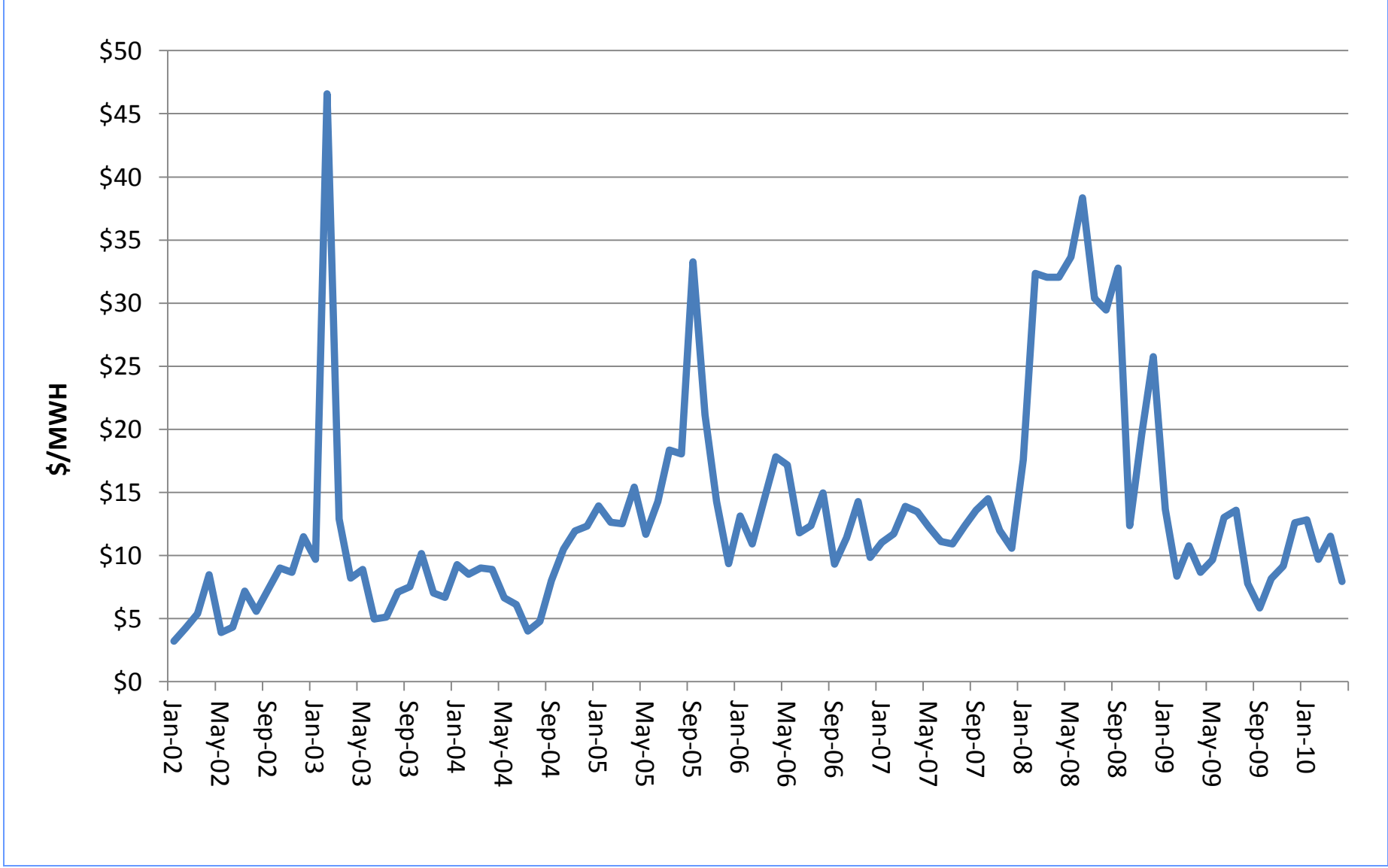
- Gas driven CF's should consider capturing “waste heat” from hot exhaust gas to create electricity for either native load use, or sale to the utility or into the market;
- Electric CF's should consider selling any operational optionality into the market through demand response programs;

ERCOT: LaaR

- Load Acting As Resource is an ERCOT Demand Response Program;
- Participants get cash payments for having their load subject to interruption during system emergencies;
- Sample value creation:
 - 6 MW x 8,760 hrs/yr = 52,560 MWh/yr
 - Load receives market prices, less fees (QSE, metering, data, etc.)
 - Based on a 85%/15% split of program revenues:

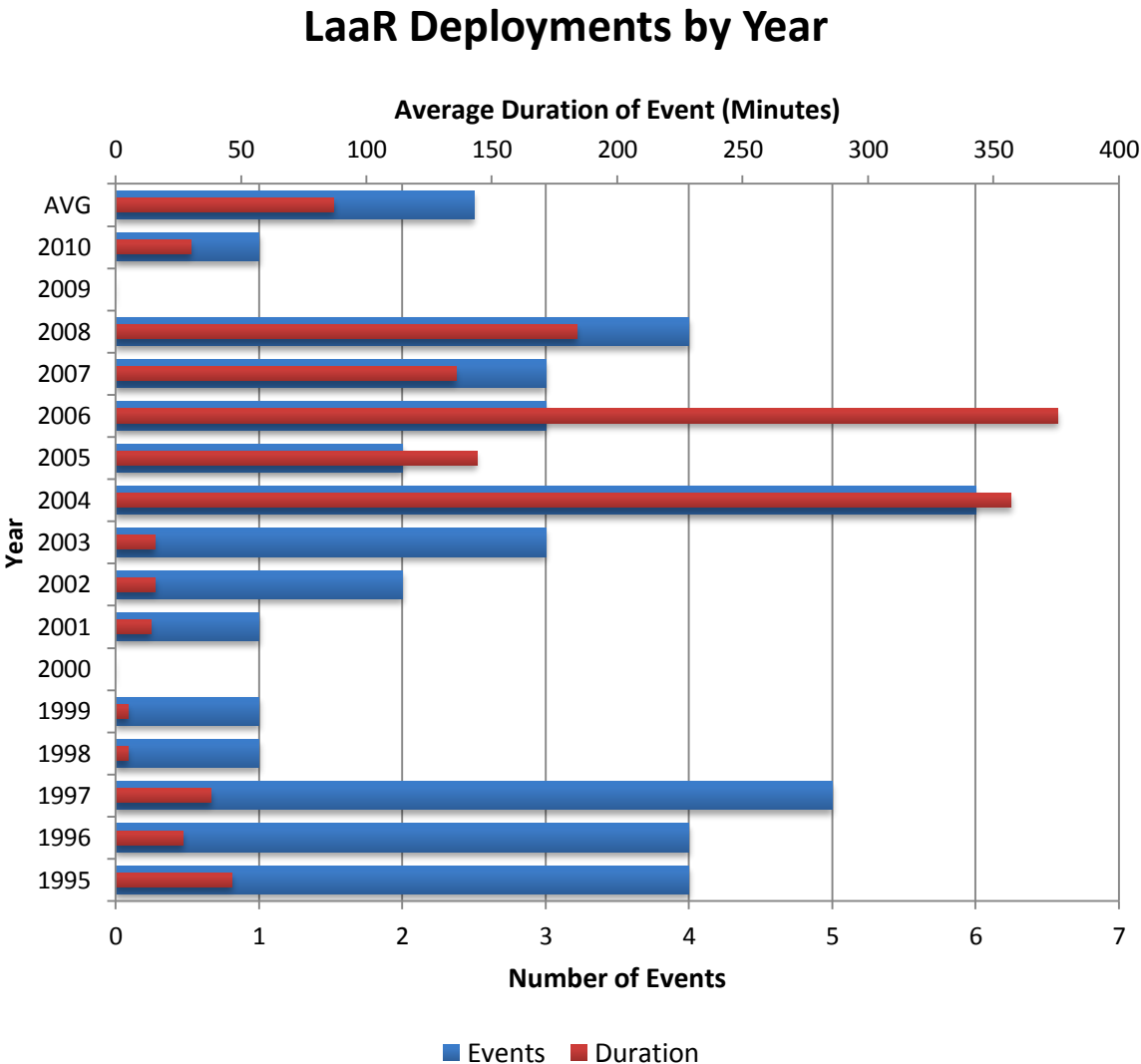
Price Case Scenario	Price (\$/MWh)	Total (\$)	QRM	QSE
			85%	15%
Low	\$6.56	\$344,925	\$293,186	\$43,978
Average	\$13.10	\$688,734	\$585,424	\$87,814
High	\$26.87	\$1,412,301	\$1,200,456	\$180,068

ERCOT LaaR Daily Average Prices



LaaR Deployment History

Year	Events	Duration	Avg Dur
1995	4	46	11.6
1996	4	27	6.8
1997	5	38	7.6
1998	1	5	5.0
1999	1	5	5.0
2000	0	0	0.0
2001	1	14	14.0
2002	2	16	7.9
2003	3	16	5.2
2004	6	357	59.5
2005	2	144	72.0
2006	3	376	125.2
2007	3	136	45.2
2008	4	184	46.0
2009	0	0	0.0
2010	1	30	30.0
AVG	2.5	87	28



Thank You.

John Bick

Managing Principal

Priority Power Management LLC

817-994-2285

jbick@prioritypower.net