Common Pitfalls in Market Price Forecasting

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Introduction

- Market price forecasters are faced with two key tasks:
  - Decide what model to employ.
    - Publicly available models, *e.g.*, GE MAPS, IREMM, EDS's PMDAM, Henwood Energy Service's Multisym) or, develop own.
    - Choice depends on purpose of forecast, forecast horizon, own view of what key factors are that drive market price for the region of interest.
  - Specify model inputs and assumptions.
- However, modeling only gets you so far.
- Moreover, there are common pitfalls that practitioners will, and have encountered in both modeling and non-modeling efforts.
- The remainder of this presentation identifies these pitfalls and offers advice on how to avoid and/or deal with them.

Common Pitfall #1: Lack of Focus on Key Factors Driving Market Prices

Sensitivity analysis of key drivers often forgone at expense of getting detailed input precise.

Uncontrollable Factors

- Three factors are particularly important — and equally uncertain — for determining the range of future market prices.
  - ***Capacity expansion plans***: timing/need for new capacity and unit mix
  - ***Cost of expansion units***: technological parameters like heat rates and cost per installed kW as well as financing terms
  - ***Natural gas price forecast*** or price of any fuel likely to be on the margin

Controllable Factors

- Market Structure: One-Part or Two-Part Market.
- Theory about equilibrium capital recovery payments.

Key Factors Driving Electricity Prices

Other Factors

- Environmental compliance requirements and costs.
- Transmission capacity, possibly allowing for greater exports of power between regions.
- Heat rate improvements, variations in demand growth, and new unit characteristics are found to have modest impacts on price.
  - *Importance of these factors is best determined by the role they play in affecting each of the primary drivers discussed above.*

Common Pitfall #2: Equilibrium Capacity Payment

There is disagreement about what equilibrium model to adopt to estimate equilibrium price.

- P = SRMC
- P = SRMC + payments only for reserve capacity
- P = SRMC + "all-in" capacity cost of a CT or CC
- Special Case: Morgan Stanley "2-Cent" Power
- P = SRMC + Capacity Scarcity Premium
  - In long-run, capacity scarcity premium < "all-in" cost of a CC or CT

Common Pitfall #3: Double Counting for the Value of Capacity

Tendency for some practitioners to increase the capacity value of the market price to account for "other" sources of revenue, *e.g.*, ancillary services.

- Most commonly arises when market price forecasts are used to estimate stranded costs.
- Some generation capacity may be used to supply ancillary services, *e.g.*, VArs, instead of producing energy for consumption.
- Valuing this service and adding it to the revenue stream of the generating units double counts the value of capacity.
- As long as some generic non-energy payment called "capacity" pays for the balance of dollars needed for entry above the energy payment, it can stand for all types of value.

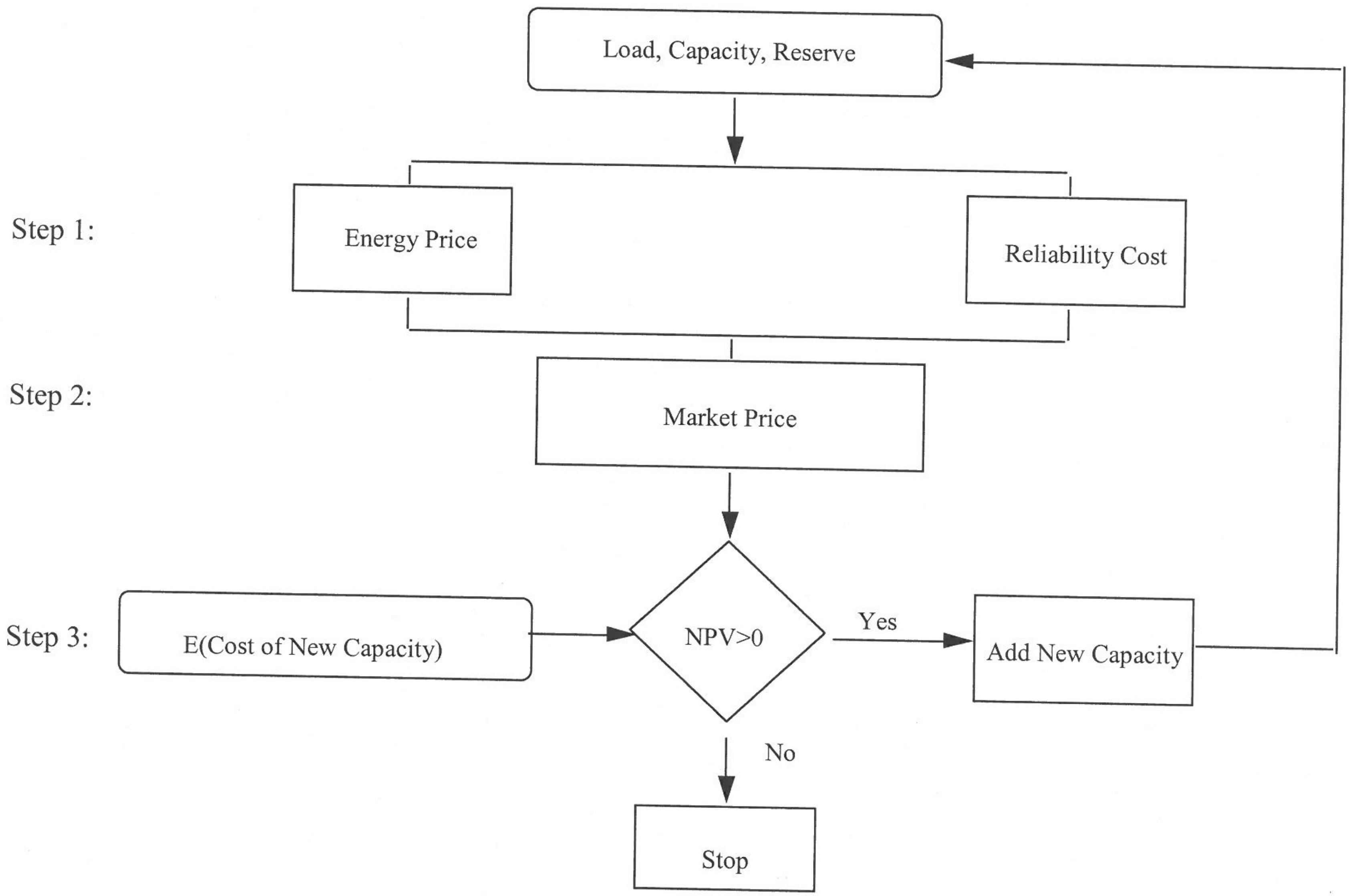
Common Pitfall #4: Capacity Expansion

- Many models rely on traditional planning methodology, *i.e.*, target reserve margin requirements, to determine capacity expansion trajectory.
  - Model simply checks to see if sufficient reserves, if not, capacity added to meet target reserve margin.
  - Capacity mix is usually pre-specified, *e.g.*, 70% CTs and 30% CCs
  - Percentages often determined by NERC forecasts and held constant through time.
- Problems
  - Ignores reality of competition: there will be profit induced entry regardless of reserve margins.
  - Does not check for viability of new plants.

Dynamic Profit-Based Capacity Expansion

- CCs, CTs or coal plants are added based on infra-marginal contribution in energy market plus "scarcity rent".
- "Scarcity rent" or the value of capacity often modeled based on loss of load probability and value of loss load.
- Recognizes that future (new) capacity will recover some of its capital costs in energy sales.
- Plants are added when forecasted contributions to fixed costs rise to make the NPV of a plant addition positive for sufficient period of time.
- Method may require several iterations.

Dynamic Profit-Based Capacity Expansion



Unplanned Capacity Addition

Traditional vs. Dynamic

YEAR	NEW COAL BASE (MW)					NEW GAS CYCLE (MW)					NEW GAS PEAK (MW)			
	TBG		EPA*	EIA**	GRI***	TBG		EPA*	EIA**	GRI***	TBG		EPA*	EIA**
	Tradition	Dynamic				Tradition	Dynamic				Tradition	Dynamic		
1996	101	-				788	-				236	-		
1997	71	-				553	-				166	-		
1998	117	-				909	-				273	-		
1999	148	-				1,156	-				347	-		
2000	237	-	-	2,000	122	1,836	2,000	-	27,600	3,996	551	-	10,801	53,400
2001	164	-				1,277	-				383	-		
2002	245	-				1,905	-				571	-		
2003	238	-				1,858	1,500				557	-		
2004	187	-				1,449	-				435	-		
2005	211	1,000	-	7,500	450	1,642	2,000	23,752	30,400	5,912	493	-	41,559	24,700
2006	220	500				1,708	-				512	-		
2007	199	-				1,555	-				467	-		
2008	258	500				2,000	2,500				600	-		
2009	234	500				1,819	-				546	-		
2010	175	-		6,900	500	1,362	2,500	47,019	33,900	1,565	408	-	18,254	18,900
2011	386	-	-			3,003	3,500				901	-		
2012	316	-				2,457	2,500				737	400		
2013	362	-				2,817	2,500				845	400		
2014	324	-				2,521	3,500				757	400		
2015	476	-	NA	15,200	5,000	3,702	1,500	NA	45,600	4,500	1,110	960	NA	16,400
TOTAL	4,669	2,500	-	31,600	6,072	36,317	24,000	70,771	137,500	15,973	10,895	2,160	70,614	113,400

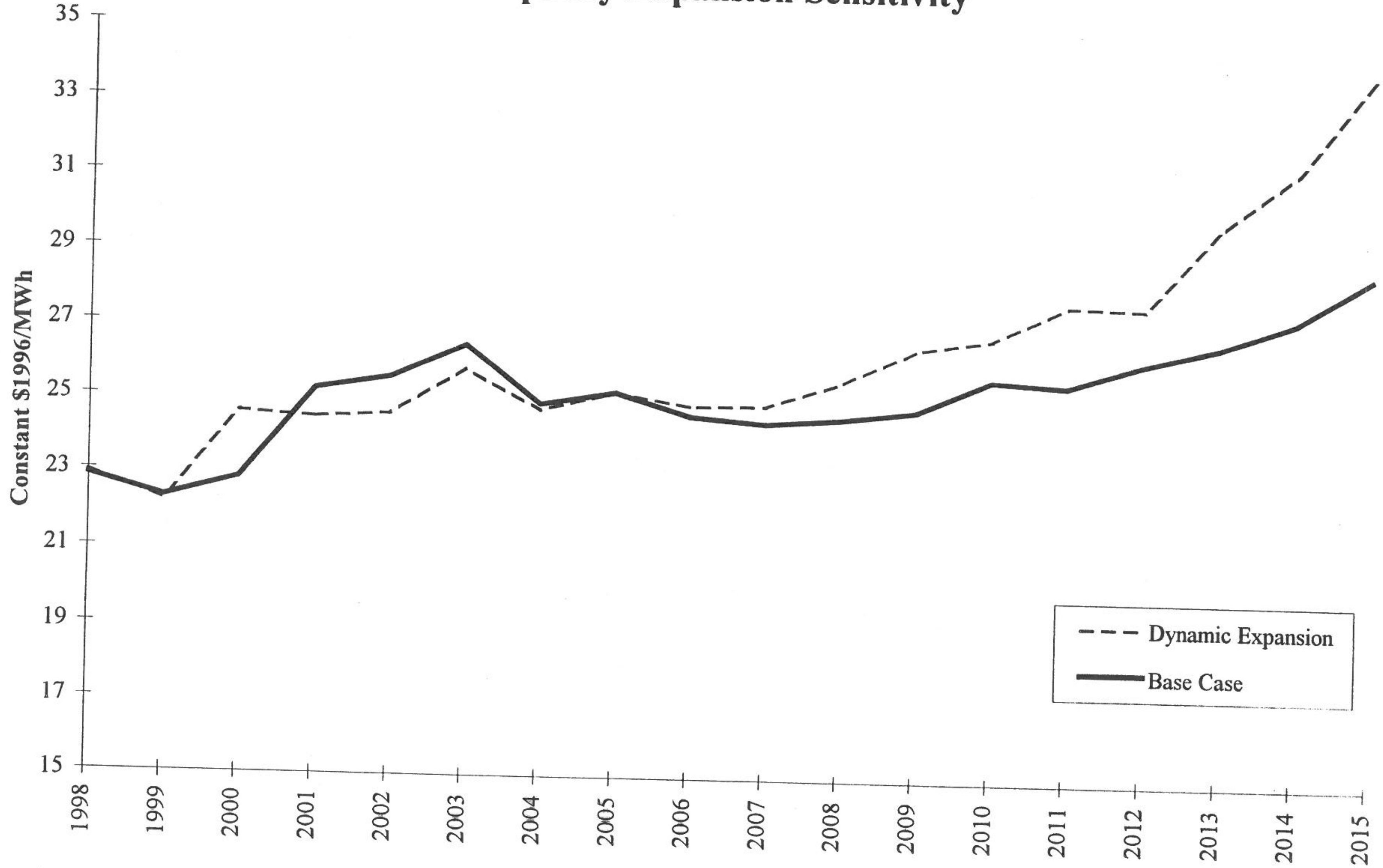
Sources: * Office of Air Radiation, " Analyzing Electric Power Generation Under the CAAA", U.S.Environmental Protection Agency, 1996 http://www.epa.gov/capi/July/base610d.txt.

** Energy Information Administration, " Table A9. Electricity Generating Capability: Reference Case Forecast", *Annual Energy Outlook 1997, p. 109*

*** Gas Research Institute, "Baseline Projection Data Book", 1996 Ed. p. 404-407

Notes: EIA and EPA Capcity Addition Forecasts represents the U.S. total capacity addition. Fuel Cells and Renewable Sources are omitted from this table. GRI Capcity Addition Forecasts represents the ECAR and MAIN new capacity additions. Gas Cycle represents both oil and gas technologies.

Figure 1
Capacity Expansion Sensitivity



Implications

- In high marginal-cost regions like Northeast, new CCs will displace older, high cost units.
  - Implies new units enter and run at high capacity factors.
  - Pushes existing base load units out of merit order.
  - Flattens out the supply curve.
  - May also force early retirements.
  - CTs, if built, don't run enough to be economic.
  - May result in increased reserve margins that make construction of new peaking units uneconomic.

- Not likely to be a steady-state, but could prevail for extended periods.
  - At some point, inefficient units have been retired, and new units are all on par.
  - New CTs become economic and may even displace existing peaking units.

- Similarly, in low marginal-cost regions, like MAIN, CTs likely to satisfy reliability requirements for extended periods.

- In equilibrium, marginal base load and peak load units require equal capacity payments for economic viability.

Common Pitfall #5: Reality Checks

Simple reality checks often overlooked.

- Calibration
  - In short-term, market price forecast should be in line with prevailing market prices.
  - In long-term, market price forecast can't be too far from generating cost of an efficient portfolio of new generation.
    - Optimum mix of baseload, cycling and peaking units.
  - Price forecasts should also be consistent with average terms of known wholesale contracts.
- Market price trajectory needs to be feasible from an economic viability standpoint for *existing* as well as new units.

Common Pitfall #6: Capacity Expansion Feedback on Gas Infrastructure

It is important to consider how much gas infrastructure might be needed for forecasted CC and CT expansion.

- Gas price forecasts don't reflect gas usage at the level foreseen by utilities.
  - Significant number of utilities are projecting 100% gas expansion.
  - Macro forecasts of gas prices usually assume 60-75% gas expansion.
- Further, it is questionable whether the gas pipeline infrastructure necessary to meet forecasted gas generation demand is in place.
  - Environmental constraints on new gas pipelines.
  - Time horizon for getting them in place.

However, some new gas replaces old, inefficient, gas with no net increase in wellhead requirements or pipes.

Common Pitfall #7: Retail vs. Wholesale Differences

- Market price of generation delivered to retail customers is different than wholesale price received by the generator.
  - Load factor differences
  - Allocation of ancillary service charges (*e.g.*, local voltage support)
  - Losses
  - Stranded Cost
- Average transmission and distribution charges may very considerably among customer classes.
  - Load factor differences
  - Voltage level at which service is taken (*e.g.*, 69kV vs. 120/240V)
  - Customer service charges

Common Pitfall #8: What Price are You Forecasting?

- Different price (conceivably) for every hour (or 1/2 hour).

- Is quoted price for 100% load factor?
  — *i.e.,* average price?

- Is quoted price for 80% load factor?

- Price for average customer?

Common Pitfall #9: Transfer Capability

- Transmission capability typically determined by NERC total transfer capability (TTC) estimates.

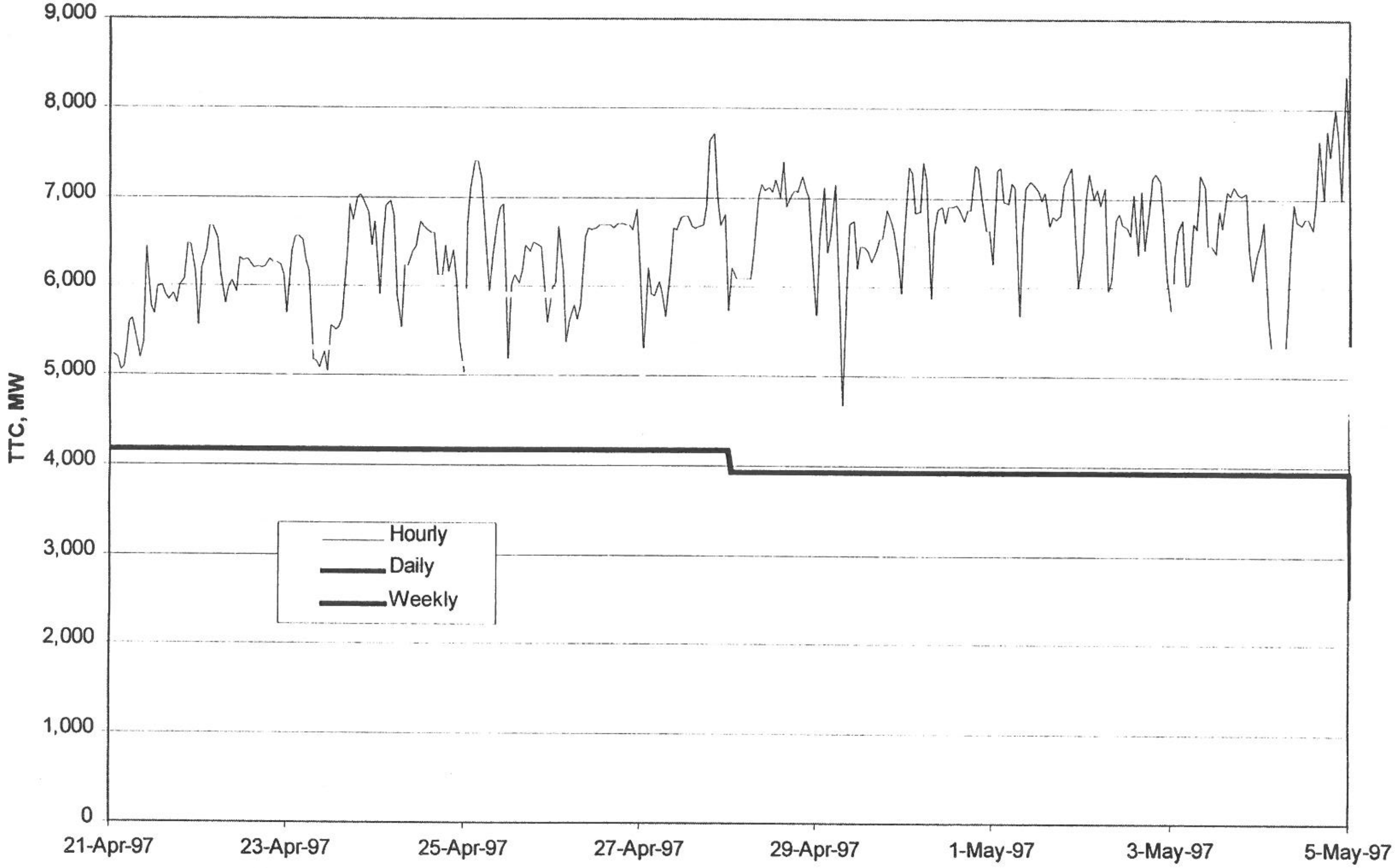
  - TTC is best available proxy for long-term forecasting of power transactions.
  - However, TTC is normally calculated at peak conditions and with other conservative factors.
  - Actual short-term transmission capability can be dramatically higher or lower (up to +/-100%)

- Implies traditional modeling may understate potential for economy energy exchanges.

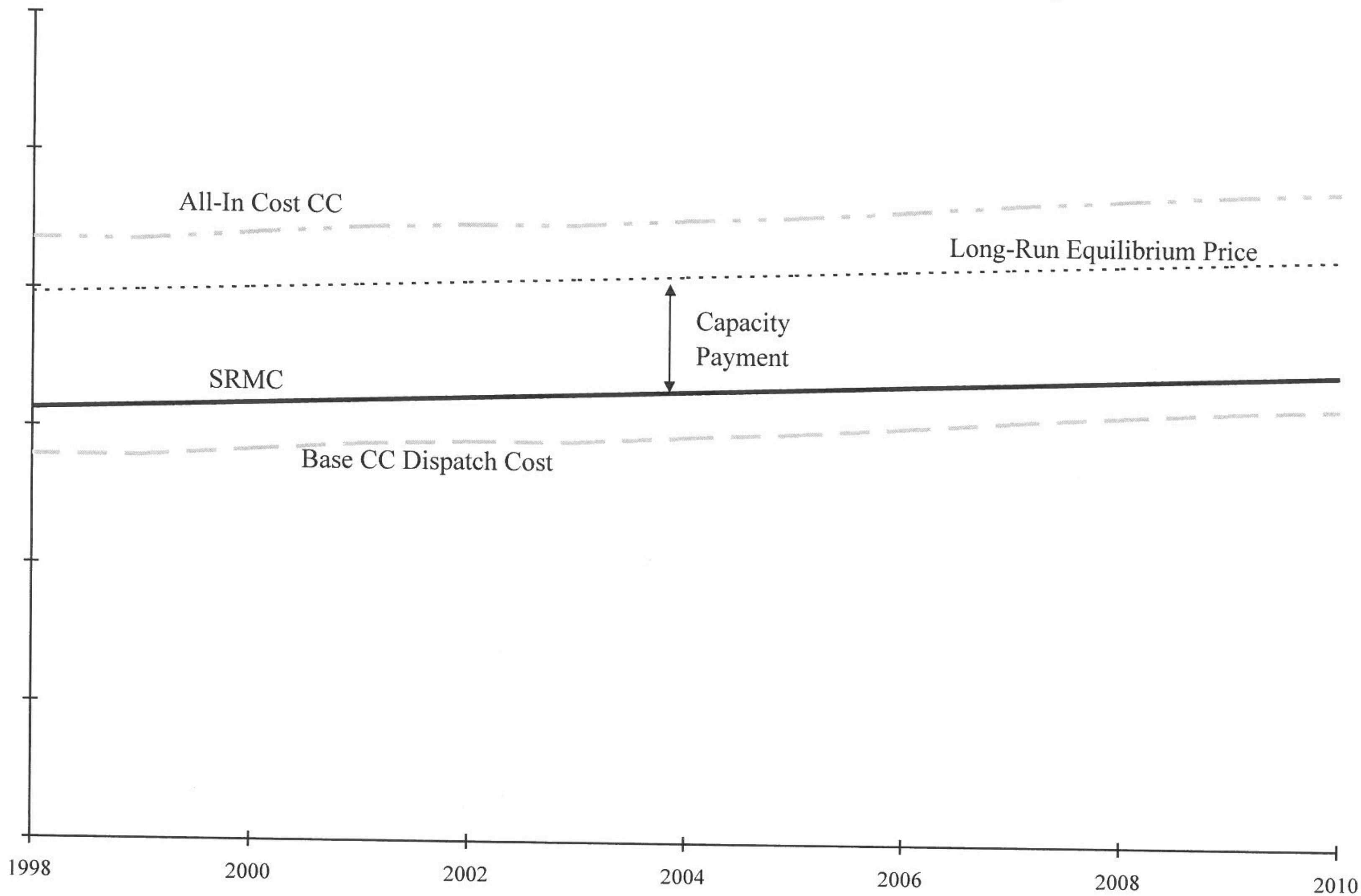
- How big a problem?
  - Potentially a large problem if concerned about market price forecasts for making short-term power deals.
  - Less of a problem if concerned about long-term wholesale transactions.

- Best solution is to do sensitivity analysis on TTC.

Figure 2: APS to PJM Total Transfer Capability - Daily View



Short-Run and Long-Run Equilibrium Price Trajectories

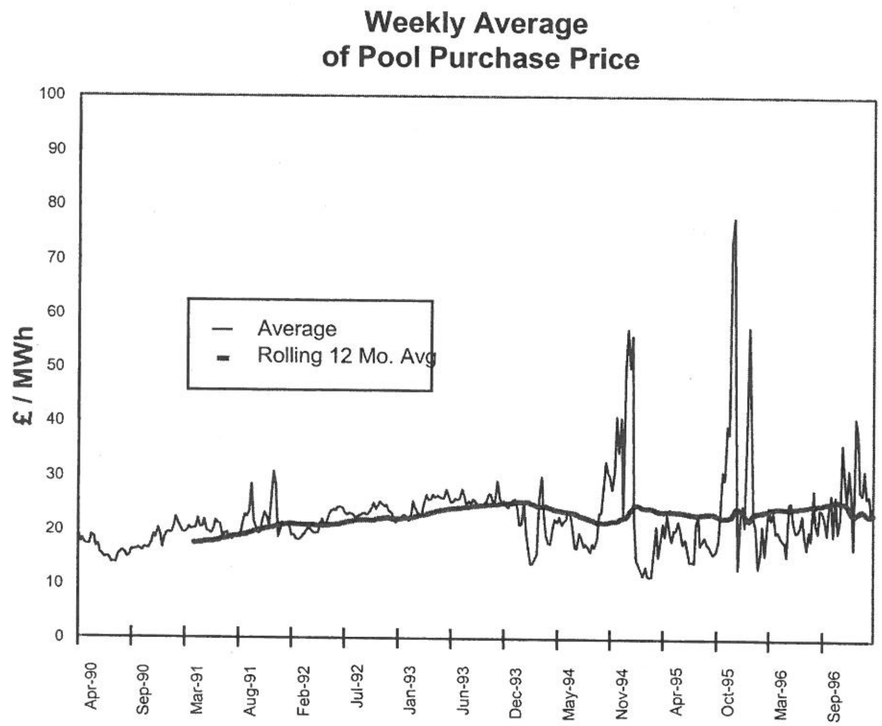


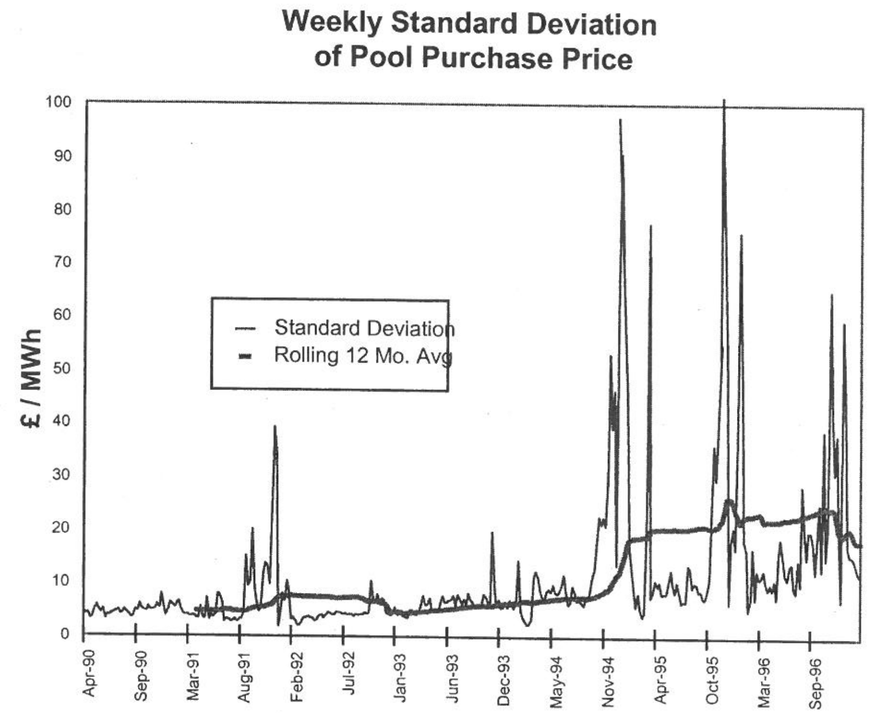
Common Pitfall #10: Confuse Precision with Accuracy

- Market price forecast practitioners can spend a lot of time banging their heads against the wall getting all the inputs 'just right'.
  - Confuse precision with accuracy.
  - Certain big variables can dwarf the precision.
- Better to spend more time focusing on impact of big drivers.
  - How long before new capacity is added?
    - Load shape -- could change due to real time pricing.
    - Reserve requirements -- could change if pool requirements go away.
    - Reduced forced outage rates.
  - What kind of capacity is going to be added?
  - How much is new capacity going to cost?
  - What is the cost of new fuel for that capacity?
    - Gas is likely to be the marginal fuel in most regions.
    - Massive disparity in gas price forecasts.

Power Price Volatility: UK Experience

Since vesting, weekly average of half-hourly pool prices has not changed much, but volatility has more than doubled (with many weeks much higher) and is now around 100% of average price.

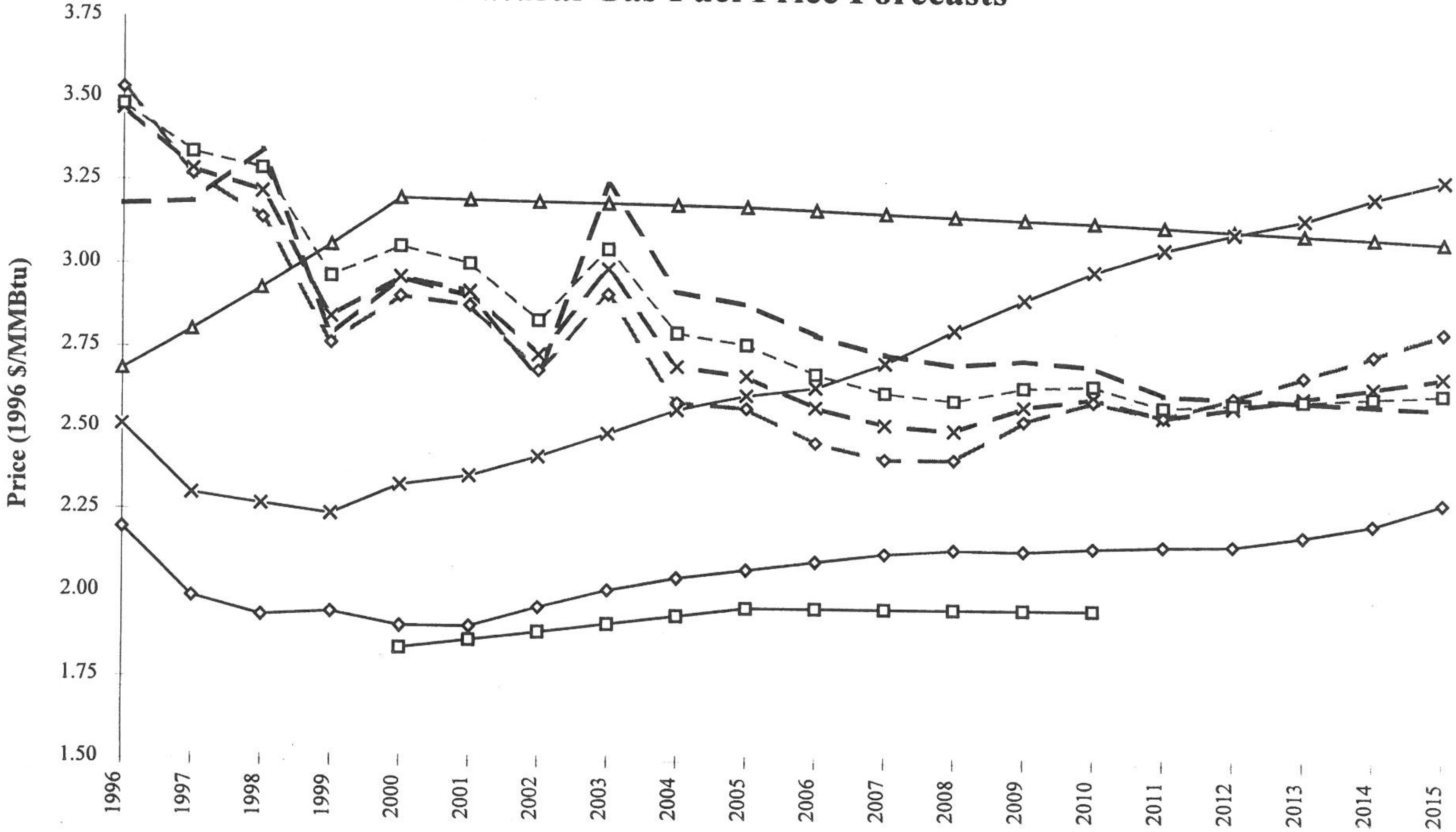




Note: Calculations: Weekly average of 336 half-hourly PPPs. Standard deviation of 336 half-hourly PPPs within week.

Source: U.K. Price and Demand Data, National Grid Company.

Figure 3
Natural Gas Fuel Price Forecasts



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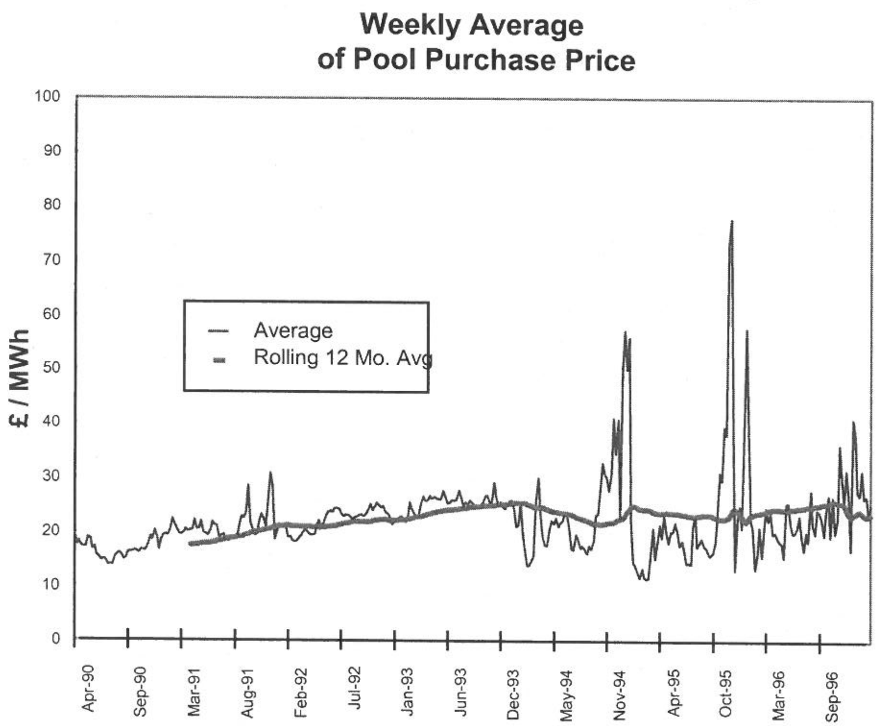

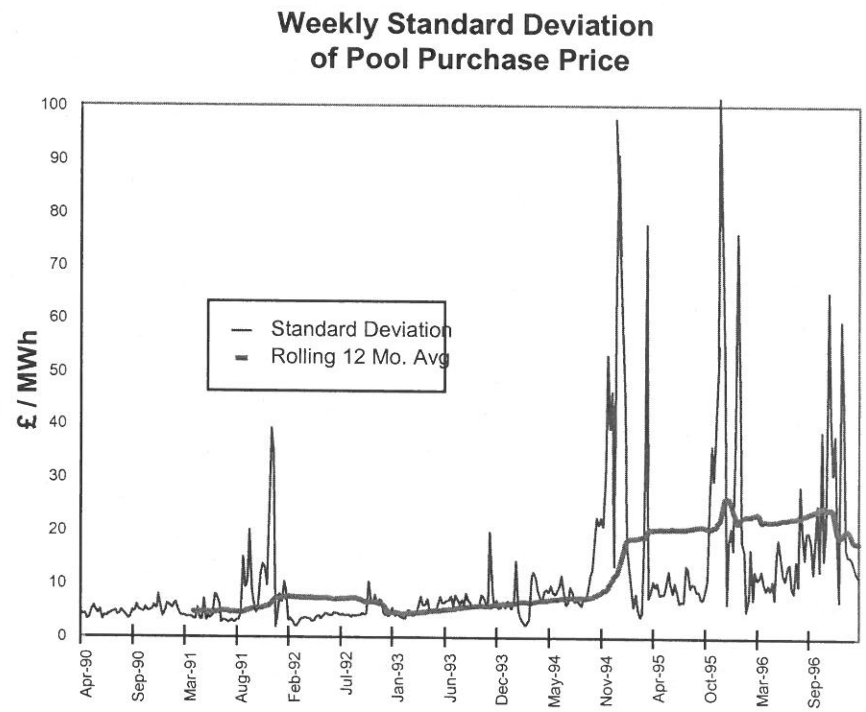

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The Brattle Group Experience

Members of *The Brattle Group* have many years of experience in utility planning and litigation consulting.

- Cases in federal/state courts and administrative agencies
- Antitrust evaluations/competitive impacts of mergers and acquisitions
- Power and gas market restructuring in the U.S., U.K., Australia, New Zealand
- Capacity planning, bulk power contracting and marketing
- Forecasting, valuation, and risk management
- Competitive access in regulated industries (railroads, telcos, natural gas, electric's)
- Transmission and ancillary services pricing
- Incentive regulation and performance-based ratemakeing (PBR)
- Strategic planning process facilitation
- Affiliations with leading academics in engineering and economics