The Pros and Cons of a Virtual Utility

Implications of Merging Generation and Retail Businesses

Introduction

Generation assets and retail energy portfolios have long been viewed as naturally offsetting, a thesis that is the foundation of both the classic electric utility model and the commercial activities of many merchant energy companies. More recently, some IPPs (both public and privately owned companies) have championed the model of combining assets and retail load. Given the substantial costs that generation owners typically pay in acquiring or building retailer, however, a rigorous analysis of the benefits and drawbacks of this strategy is in order.

The most common arguments in support of combining generation and retail load include:

- Reduced hedge costs and potential collateral calls, since fewer OTC or exchange trades are required to hedge the net position.
- A more efficient use of collateral posted at ISO/RTOs, also a result of position offsets.
- A belief that the two businesses are complimentary on long time-scales. For example, a secular drop in energy prices adversely impacts the value of generation, but can be favorable to retailers due to higher spreads (headroom) between utility default service and prevailing market prices.

On the other hand, a generator that decides to enter the retail markets as a natural hedge inevitably inherits a new set of risks. Variations in load are in general statistically different from the quantities that a generation asset will produce. Fluctuations in load arise from short term weather fluctuations and larger "macro" perturbations to a customer base. How the two sets of risks interact is not obvious, and in fact depends on the details of both the generation assets and the retail customer base.

In what follows we will compare a generation portfolio hedged as a stand-alone enterprise versus one operating in tandem with a retail operation. In particular we will address:

- How do the distributions of future cash flows differ? Is the risk position of a blended operation better or worse than for stand-alone generation?
- How much are hedge costs and collateral postings reduced?
- Are there unmanageable or unquantifiable benefits or risks arising from combining the two asset classes?

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The answers to questions like these are situation dependent. A generation portfolio consisting a CCGT in New Jersey in the PJM market has altogether different dynamics than peakers in COMED or wind in upstate New York or Texas. Moreover, the type of retail business being considered can have a meaningful impact. A business with a heavy residential component is statistically quite distinct from one focused on larger commercial and industrial customers.

Our working example will consist of a 700MW CCGT generator and hybrid Residential/C&I load book, both settling against PSEG day-ahead prices. The large CCGT footprint and substantial retail activity in the greater Northeast render this a realistic case to consider. More importantly, our analysis of this portfolio illustrates how any bespoke situation can and should be treated. For a different asset base and retail portfolio the answers may change, but the general approach that we follow below would not.

We will take the viewpoint of a generation owner contemplating entry into the retail energy sector. The effective date of the analysis is 12Nov2018; all results are consistent with trade market prices on this date. The time horizon over which we analyze the behavior of the portfolios in will be calendar year 2020. The results below are based upon statistical analysis of historical weather, demand and spot prices, simulation of future realizations of such and realistic dispatch algorithms for generation.

Analysis of Stand-Alone Generation

The first step in analyzing any hedging program or potential acquisition is to develop a thorough understanding of the existing portfolio. Figure 1 below shows high level economic and operational attributes of the 700 MW nameplate capacity CCGT by calendar month. The top plot shows the expected cash flows; by this we mean the cash realized from dispatch of the asset for energy, paying for fuel, start costs and VOM, but not including capacity or other standard "pro forma" components such as wages, taxes and the like. The lower plot shows the capacity factor, defined here as the expected number of MWhs produced each month over the maximum possible.

Key points:

- The expected cash flows vary between roughly \$3m and \$7m per month. This gives a reference economic value.
- The asset runs less in the winter time as a result of gas price spikes.

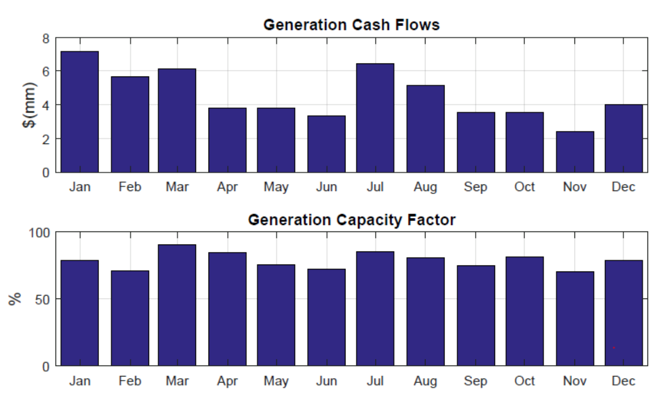

Figure 1: Expected cash flows and capacity factor by month

Statistics like these do not in and of themselves shed much light on the nature of the embedded risks of the asset. A CCGT consumes natural gas, which the owner has to buy, and produces electricity which is sold into the spot market. The spark spread is the difference between the value received for the electricity sale and the cost of fuel to produce it in units of $/MWh. A modern CCGT requires a little under 7 MMBtus of natural gas to produce one MWh of electricity, making the 7 heat rate spark spread a natural index for explaining cash flows.

To this end Figure 2 shows the simulated on-peak spark spreads for Jan2020 in the top plot and the distribution of the *unhedged* cash flows[1] for the generator.

Key Points:

- Spark spreads range from effectively zero (which occurs during very cold and high gas price environments) to well above $50/MWh.
- This broad range is reflected in the distribution of cash flows for the owner who may receive anywhere from zero to $20m for this month.

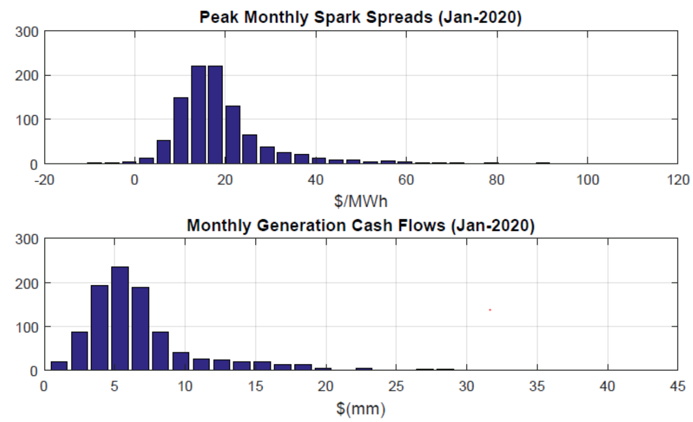

Figure 2: Distribution of monthly spark spreads and cash flows (peak)

The large spread in these distributions motivates many asset owners to hedge price risk.

Figure 3 provides a more direct connection between spark spreads and the asset, showing cash flows from on-peak generation versus the average monthly peak spark spread.

Key Points:

- The dominant linear relationship is why hedging using a standard vanilla forward contract is useful.
- The scatter around the overall linear structure means that a simple forward hedge still leaves the owner with non-trivial residual risks.

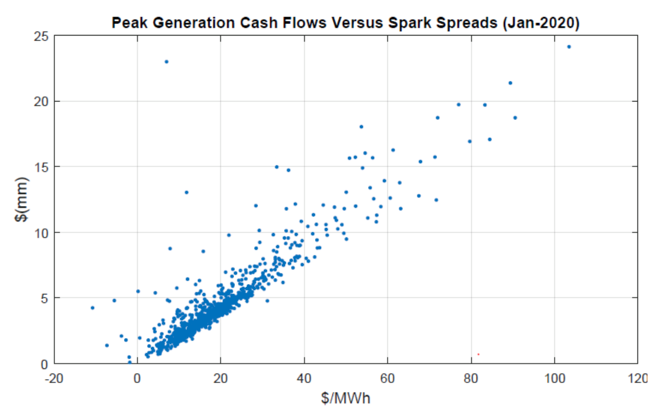

Figure 3: Cash flows from on-peak generation versus spark spreads

[1] The cash flows shown here are purely for energy assuming 100% dispatch for such. Ancillaries will contribute to the cash flows of a CCGT, but will also reduce energy revenues as modeled, so we consider this to be a reasonable representation of what the asset will produce, excluding capacity revenues.

It is these residual risks that asset owners, who thought they were hedged, have noticed during periods of extreme temperatures and spot prices. It is also these residual risks that matter when it comes to assessing the relative merits of a retail position as a hedge.

Figure 4 quantifies just how much can be accomplished by using standard forward trades to hedge the position. This figure shows the standard deviation of cash flows for the unhedged position (yellow) and the hedged position (blue). A perfect hedge would result in the hedged position having zero standard deviation.

Key points:

- In the non-winter months basic forward price hedges work well, effectively eliminating the risk.
- In winter months a significant residual risk remains after hedging.
- This is a CCGT phenomenon. Peakers, baseload, wind and solar will each have their own particular statistical response to such basic hedging strategies.

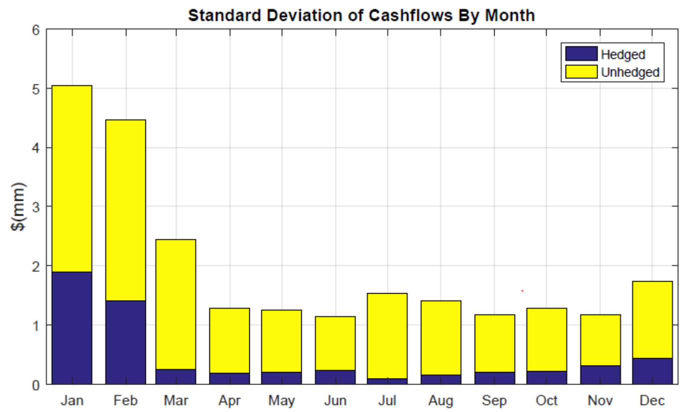

Figure 4: Cash flows from on-peak generation versus spark spreads

Finally, there is another very useful view into the origin of the hedge slippage in the winter months. Figure 5 shows cash flows for the *hedged* generation portfolio on a 16Jan2020 versus daily temperatures at LaGuardia (KLGA). The feature that stands out is the high volatility at low temperatures.

Low temperatures can result in natural gas price spikes. Such price spikes can be extreme, often sending spot prices in the Northeast up by factors of 20 or more relative to "normal". When this happens the natural gas purchased as part of the hedge can be sold back to the market at these premium prices, and the electricity required for the power hedge can be bought in the spot market (the market has switched to cheaper fuels). In short, it is better to stop generating and sell the gas.

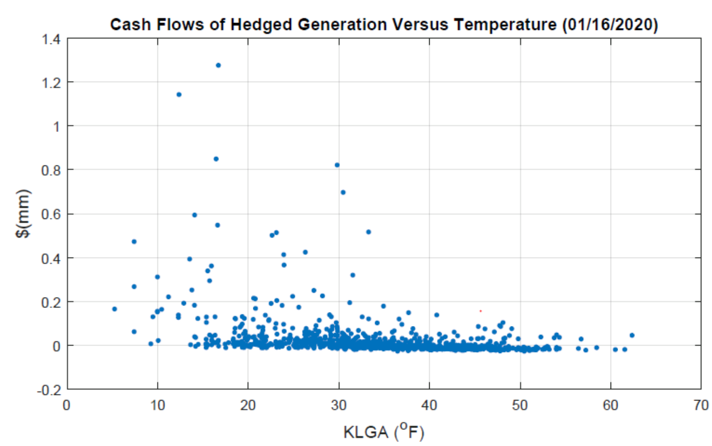

Figure 5: Cash flows from a hedged CCGT versus temperature

It is the unpredictable nature of gas price spikes that results in the higher cash flow spreads at low temperatures. This behavior turns out to offset retail exposures in a natural way.

Analysis of Retail Electricity Portfolios

A retail electricity portfolio consists of a set of electricity sales to individual end users. The simplicity of the description belies the challenges involved in getting an accurate picture of the associated risks. There are several reasons for this:

- A moderately sized retail portfolio of moderate size will have several hundred thousand individual contracts defining the terms of sale to each customer. While these contracts usually share common structure, the details of usage behavior and likely cost structure vary by customer.
- The information available on individual customer usage is often at the monthly time-scale, impeding analysis of hourly usage fluctuations to which retailers are exposed.
- A retail short involves a litany of non-energy costs that can vary by utility and market.
- Commercial activity inevitably involves the processing and analysis of large quantities of data, the integrity of which is not always guaranteed.

A well run retailer *should* have technological solutions to most of these issues, in which case the risk positions can be viewed in aggregate.

Our working example for a retail short is the PJM Mid-Atlantic hourly load as published by the PJM ISO settling against PSEG zonal prices. This load is a blend of residential, commercial and industrial users and is, therefore, a reasonable proxy for a retail short. A few comments:

- We have sized the load to be a peak short of 200MW, to be compared to the 700MW nameplate capacity for the CCGT.
- The short position will settle at PSEG zonal prices, just as the CCGT did.
- The short position will pay the retailer a fixed price[2], set to be \$3/MWh above breakeven. This is somewhat above what is typically achieved for commercial and industrial sales, but below residential.

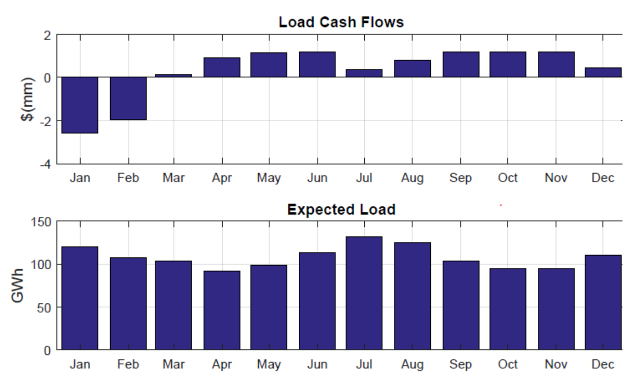

Figure 6: Cash flows from a hedged CCGT versus temperature

Figure 6 depicts the economics of the short position:

[2] Many retailers rely heavily on month-to-month (variable) pricing in which prices are set for the end user on a floating monthly basis. Such transactions do not serve as useful commodity price hedges for an asset and hence are implicitly excluded in this work. This fact is an important consideration for an asset owner considering acquiring a retail book.

- The top plot shows expected cash flows, which are negative during the expensive winter months, but positive over the year due to the $3/MWh of margin.
- The bottom plot shows the expected load (short) which is greatest during high demand summer and winter periods.

The response of a fixed price load transaction to spot prices is shown in Figure 7. This is analogous to Figure 3 for generation, but is decreasing with electricity price as expected; the position is, after all, short electricity. A stand-alone retailer will typically hedge this position by purchasing the expected delivery quantity.

Key Points:

- In this figure the x-axis shows electricity prices, while for generation (Figure 3) we used spot spark spreads.
- From the perspective of electricity price risk these two risks are offsetting.
- Hedging a CCGT will still require natural gas purchases to hedge the embedded natural gas short position.

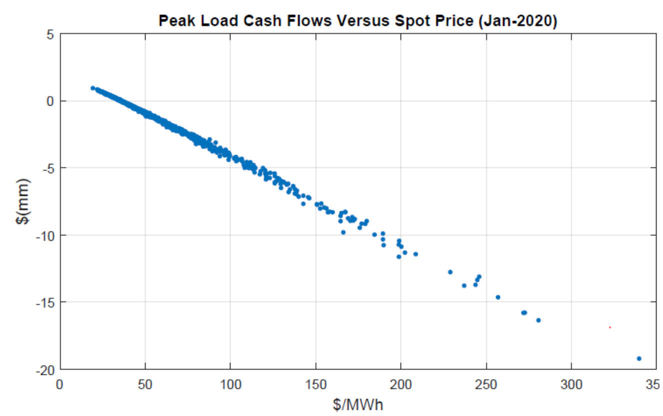

Figure 7: Cash flows from on-peak load short versus spot prices

It is particularly interesting to look at the response of the *hedged* load position versus temperature, much as we did earlier for the CCGT. Figure 8 shows the results.

Key Points:

- There is a nontrivial residual risk after the forward hedge, especially at low temperatures.
- Comparing this to Figure 5, the residual risks of the hedged load position appear to offset that of the CCGT.

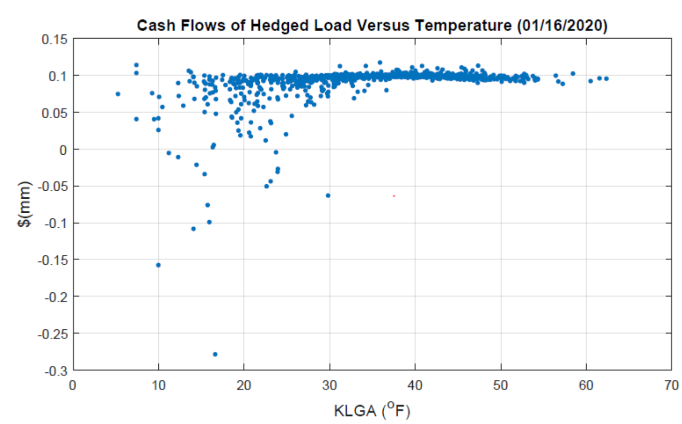

Figure 8: Cash flows from a hedged load short versus temperature

Analysis of the Combined Portfolio

The fact that the hedge slippage for a CCGT and that for a load short are apparently offsetting suggests that the combined portfolio could actually perform better together. This is in fact the case. Figure 9 compares the standard deviation of two portfolios:

- The CCGT stand-alone hedged with forward contracts.
- The CCGT and the load short together, with the residual exposures hedged with forward contracts.

It is clear that the combined portfolio is less risky during winter months, as expected given the offsetting hedge slippages for the CCGT (Figure 5) and the load short (Figure 7). Importantly, hedge performance in the remaining months is comparable and the net effect of combining the positions is positive in totality.

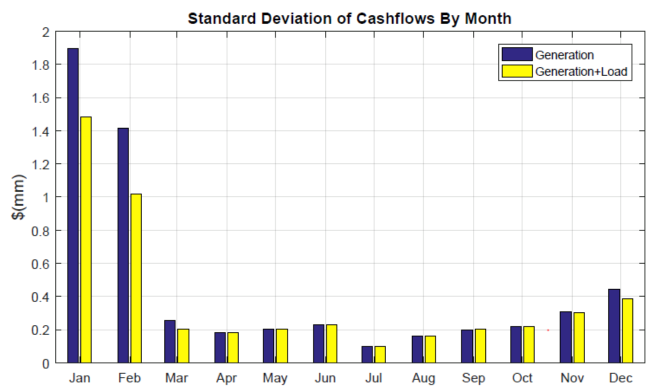

Figure 9: Comparison of portfolio hedge performance

The punchline is that from the perspective of energy price risk alone, a combination of generation and retail shorts can, at least in some cases, perform better than a stand-alone asset. We turn next to the benefits of position netting.

Implications for Hedge Costs

The preceding analysis focused solely on the price risk implications of merging generation and retail businesses. With the risk position not degraded by combining the portfolios, and in fact improved, the next issue to address is how much netting reduces hedge costs and collateral postings.

In our working example the fuel position of the CCGT has not changed and must be hedged in the same way whether the asset is stand-alone or combined with the retail short.[3] A plausible scenario for hedge cost reduction is shown in Table 1 below which shows the current exposures and the costs associated with hedges:

- The volume columns show the hedges required (positive values imply a long position and the hedge would be a sale).
- The costs assumes were $1/MWh for peak and $1.50/MWh offpeak. This is higher than what a trader will typically see on the screen or as reported in broker sheets. However, the position size is large relative to standard blocks and asset owners and retailers generally pay higher spreads than dealers. So we view this as a reasonable estimate.
- “CCGT Benefit” shows the reductions in volume required in comparison to the CCGT stand-alone hedge.
- “Total Benefit” shows the reductions in reference to the total hedging costs for the two separate business separately. The savings over one year in total for the combined business is slightly above $4m.

	Volume (GWh)			Cost ($m)		
Portfolio	**Peak**	**Offpeak**	**Total**	**Peak**	**Offpeak**	**Total**
CCGT	2,619	3,584	6,203	2.62	5.38	7.99
Load	(663)	(923)	(1,586)	0.66	1.38	2.05
Combined	1,957	2,660	4,617	1.96	3.99	5.95
CCGT Benefit	663	923	1,586	0.66	1.38	2.05
Total Benefit	1,326	1,847	3,172	1.33	2.77	4.10

Table 1: Comparison of Hedge Costs

[3] There is, of course, the potential of starting or acquiring a retail with a natural gas footprint. This can also be analyzed and would have similar benefits. Here we are confining our attention to electricity.

Other Considerations

We conclude by discussing briefly a number of other considerations, some of which are amenable to rigorous quantitative or financial analysis, others which are outside of modeling paradigms and are more subjective in nature.

– *Working Capital*

There are working capital considerations for the two businesses. For generation fuel purchases from supplier are often not margined up to certain thresholds and are billed after the delivery, while electricity sold into the electricity market is paid for by the ISO/RTO several times a month (weekly for PJM), endowing generation with what is typically a working capital surplus. Similarly retailers are billed by the ISO several times per month. However, due to lags in meter read schedules retailers collect customer payments from utilities on average several weeks after the ISO has required payment. This renders retailers in working capital deficit. The two business are, therefore, complimentary from the perspective of working capital.

– *Collateral Postings*

Most asset owners hedge price risk in forward markets on time horizons of a year or two, perhaps more depending on strategy and risk covenants. In general, dealers or exchanges require dollar-for-dollar posting of any mark-to-market deficits arising from such hedges. In periods of high price volatility these can stress available sources of cash and LCs. In some instances structure credit arrangements are made which use liens against the physical assets to support trading, thereby reducing or eliminating the threat of large collateral cash flows. However, a short retail position can also serve as a mitigant, due to reduced hedge volumes as in Table 1. The effect depends substantially on the asset base; baseload generation length matches retail shorts more effectively here than CCGTs, which already have offsetting fuel hedges.

ISO collateral requirements are based on net exposure to the ISO. As such asset owners typically avoid the need to post collateral at the ISO, however the posting requirement can be burdensome for retail/load serving entities. Merging the two businesses can eliminate the collateral obligation associated with the retail load, thus providing savings.

– *Changing Retail Footprint*

The underlying assumption in our working example was that the retail portfolio is considered only within the same zone in which the CCGT is located. In fact, retail shops will tend to have a commercial footprint over many zones, with the evolution of the risk positions driven largely by the head room (margin) available relative to utility default service or their other competitor's offerings. Nonetheless, a retail operation can target zones of interest, especially when the retail margin adjusted for the hedge costs savings above is positive. Moreover, basis hedges can transfer retail short positions to the location of generators.

– *Nodal Price Risk*

Generators receive nodal prices, as opposed to zonal prices at which the vast majority of MWhs are settled on the retail side. Nodal to zonal price spread risk can be significant, but remains a component of the asset portfolio risk since there is almost no availability of nodal price hedges from hedge providers or exchanges. An asset owner will either warehouse risk or turn to FTR markets in either situation.

– *Ancillary Services*

Depending on the asset, generators are typically net receivers of ancillary revenues, while retailers are short ancillaries. Similar to the energy analysis, an analysis of ancillary service revenues and costs can be performed to identify the net exposure. The connection between ancillary receivables and liabilities is more tenuous; a generator must be dispatched for ancillaries which may or may not occur; a retailer is always short the exposure. While merging the two businesses is definitely risk reducing, the effect is harder to analyze rigorously.

– *Capacity Revenues and Costs*

In some ISOs (e.g. PJM) a generation portfolio receives capacity revenues, with prices set by annual auctions well in advance of a delivery (planning) year. These revenues are contingent on the generating units providing reliability support during peak demand periods. Unlike a generation portfolio, a retail portfolio is short these costs, with adjustments made by zone through a set of arcane ISO/utility-specific rules. In the current environment of relatively low energy prices, capacity costs constitute are large fraction of the cost to serve load, often well in excess of 25% of the total bill. Capacity costs, therefore, constitute an important risk embedded in retail books.

On the face of it, capacity positions would seem to offset between generation and load. However, generators often lock in capacity revenues in ISO-administered auctions for tenors beyond that of the typical retail portfolio. In addition, capacity requirements for loads are reset annually, somewhat decoupling price exposure from that of generation. From a risk perspective we view the long and short capacity positions as at best marginally offsetting.

However, capacity charges present two additional risks for retailers:

- Accurately computing the capacity cost for a give load can be *very* challenging. The methodologies in some ISOs are particularly convoluted and opaque. There is a long history of capacity cost “road kill” in the retail folklore. It is important that both the staff and the technology at a retail shop are of a caliber to get these costs right.

- Customers typically pay for energy and all non-energy costs, in particular capacity, through a fixed price per kilowatt-hour consumed. If realized volumes are different than forecasted, there is a risk of under or over recovery of such costs. This risk, which is amplified by the high percentage that capacity costs now contribute to a typical bill, can be rigorously analyzed and hedging strategies adjusted with appropriate technology. In our experience, however, relatively few shops get this right.

– *Macroeconomic Impacts*

More stable loads tend to make better hedges to generation assets. Short term fluctuations due to weather can be quantified and the effects understood. Large changes in demand patterns arising from global economic factors are another matter. The credit crisis of 2008-2009 is the best historical example of problems that can arise.

People knew before the credit crisis that the economy could affect demand. Aside from few localized events, however, this concept was little more than a stylized fact. The collapse during the credit crisis was anything but local, resulting in a decrease in expected usage of nearly 10% for many loads around the country; truly eye-popping decreases and coincident with dramatically falling prices. This severely impacted the effectiveness of load as a hedge in a way that was not particularly predictable. The impact of large-scale events, whether economic or arising from unexpected technological development, is hard to model but should be kept in mind as a qualitative consideration.

Conclusion

Retail portfolios can be natural complements for generation assets. Whether or not a given retail book is a good fit for a particular asset depends upon the details. Our goals above were two-fold. First, we wanted to enumerate the most important issues involved in assessing whether or not a generation owner should take the plunge into an energy retail business. Second, we intended to show how these issues can and should be addressed proactively.

To summarize:

- Combining a set of generation assets with a retail portfolio can be risk reducing.
- Merging the two types of businesses will yield savings on hedge costs and can potentially reduce collateral postings, working capital and exposure to non-energy prices.
- The technological requirements to properly forecast future exposures and provide forensic back-casts of historical performance are substantial. These should also be part of any due diligence prior to acquisition.
- These are not "one-size-fits-all" considerations. The nature of the generation assets, the composition of the retail portfolio, and the integrity of the businesses operations all impact whether or not combining these two types of businesses makes sense.