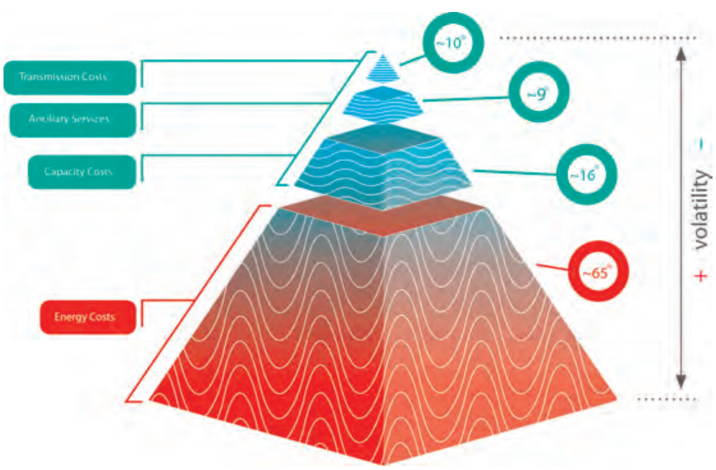
Strategic Energy Procurement: Understanding Electricity Pricing in PJM

Competitive energy markets have come a long way in bringing more options to commercial and industrial customers. In PJM, retail electricity providers can now customize pricing offers with dozens of cost components that can be tailored to specific consumer risk requirements. This has allowed buyers to make more strategic procurement decisions based on key operational priorities and energy usage patterns, but it has also added a new layer of complexity to the way energy is priced.

Because there are so many variables at play, GDF SUEZ Energy Resources created the energy pyramid to give buyers a better understanding of electricity pricing components and how they behave from a risk management perspective.



At the base of the pyramid is the energy costs category, which represents the total price of the energy a business consumes. These pricing variables can be very volatile, making it difficult to predict future costs.

The remaining components are included in the delivery category, which breaks down the cost to flow energy from the output side of the generator to a meter into three subcategories: capacity costs, ancillary services costs, and transmission costs. These components are much less volatile, change less often, and are driven mostly by regulatory bodies and independent system operators who manage the reliability of the electric grid.

Understanding the way costs are categorized in the energy pyramid is an essential first step to gaining clarity in electricity pricing. Even more important, however, is knowing how pricing components are structured and the potential methods suppliers can use to present these variables in a product offer.

Energy Costs

Six cost components make up the energy portion of the pyramid and can account for up to 75 percent of a commercial electric bill. These include hub energy, zonal basis, shape, straddle, imbalance, and losses.

The hubs in *hub energy* are not physical locations but rather an arithmetic average of electricity prices, determined in bulk wholesale power markets at a particularly liquid pricing point. This component carries a market-based risk that can be mitigated by suppliers who hedge fixed-price exposure on behalf of their customers or by customers who float this component based on the day-ahead or real-time index. Pricing is determined by usage, with location, contract terms, and time of use as key factors in determining overall costs.

Zonal basis – also known as congestion – is the price differential between the hub and load zone that establishes a measure of locational value for various load pricing points. This cost component also carries a market-based risk, which is primarily hedged through swaps or Financial Transmission Rights (FTRs). FTRs are instruments that base charges on hourly day-ahead price differences across the transmission path. Overall pricing is determined by usage, with location, contract terms, and time of use as key factors in determining overall costs.

For both hub energy and zonal basis, it's important to understand that fixed pricing does not include basis to the zone. Energy delivered to the zone is normally included. However, it can be priced at the hub. In that case, basis to the zone is passed through or billed as a line item. Block energy can be priced as either hub energy or zonal energy.

Shape refers to the cost of serving a customer's unique load shape relative to a flat, round-the-clock block over the same time period. Pricing for this component is determined by mapping a customer's unique energy usage pattern against hourly prices. Generally speaking, a lower load factor typically results in a higher shape cost.

This component carries a hybrid of market-based and non-market-based risk that can be hedged or mitigated through risk premiums. Customers can change shape charges by shifting their load usage to off-peak hours.

Straddle is the risk premium associated with the volumetric swing provision of a contract. This component covers the risk of the customer's actual load and price shape varying from the historical load and price shape upon which the pricing offer is based.

Like shape, straddle costs are determined by energy usage patterns. It also carries a hybrid of market-based and non-market-based risk that can be hedged or mitigated through risk premiums or contract language that transfers the risk to the customer through wider/narrower tolerance bands.

Imbalance covers the risk of price and load changes between day-ahead schedules/prices and real-time usage/prices. It essentially covers the risk of a customer's actual load diverging from load forecasts.

This cost component, which is also determined by energy usage patterns, carries a hybrid of market-based and non-market-based risk that can be mitigated through risk premiums.

Buyers should know that imbalance is included in fixed-price and day-ahead index products and is not applicable in products based on the real-time index. Be aware that fixed-price and day-ahead index pricing offers that allow for real-time settlements for both energy and operating costs are based on the supplier's internal load forecast.

Losses include the cost of energy that is dissipated in transmission and distribution lines. It covers the expense of additional energy that load serving entities are required to supply to the grid to overcome resistance in the transmission and distribution system.

Pricing is determined by energy usage patterns, with zone, contract terms, utility, and voltage class as key factors in determining overall costs. Losses carry a hybrid of market-based and non-market-based risk that can be hedged.

In a fixed-price product, losses can be included in the cost or passed through as a line item. With an index product, losses can be included in the adder but are more commonly passed through as a line item.

When reviewing a pricing offer, it's important to determine whether or not this cost component includes both transmission and/or distribution losses. If the proposal only outlines transmission losses, then distribution losses will be an additional charge at the time of billing.

For a true comparison, it's essential to determine where and how line losses are accounted for in pricing proposals. Determine if the loss percentage is stated correctly, particularly when the cost component is passed through as a line item, and understand if losses are included in the price or are volume-adjusted as a line item at the time of billing. Although the latter may seem more attractive in a proposal, the actual calculated cost on the bill may be a lot higher than the charge associated with a contract that includes losses in the total price.

Capacity Costs

Capacity costs – which can account for up to 15 percent of the total bill – are included in the delivery section of the energy pyramid.

The intent of a capacity market is to ensure resource adequacy by sending appropriate price signals to encourage resources to provide sufficient and deliverable capacity in locations where it is needed. In PJM, each load serving entity is charged for its daily unforced capacity obligation priced at the applicable zonal capacity price for the delivery year.

These costs carry a hybrid of market-based and non-market-based risk that can be hedged. Pricing is based on consumption, with contract term, location, and load factor as key aspects in determining ultimate costs. Generally speaking, lower load factors result in higher capacity costs.

This component has a large degree of variability and can be accounted for in various manners by each supplier. Because of that, it is critically important to determine whether or not a supplier is using the correct peak load contribution (PLC) for the proposed contract term. PLC, which is determined based on an individual consumer's portion of demand on the total peak load of the electric grid, is established annually for the coming year in June and runs through May. Suppliers can use expected PLC or current capacity prices (with true-ups), among other tricks.

Also, identify the capacity rate upon which the proposal is based. These rates are known several planning years in advance and are available at www.pjm.com.

Ancillary Services Costs

Ancillary services costs are also located in the delivery portion of the energy pyramid and can make up about 5 percent of the total electric bill. These variables not only change from market to market but can also be presented differently by each supplier. The following components are included by GDF SUEZ Energy Resources in all pricing proposals for consumers in PJM.

Regulation and Frequency Response Service covers the cost to balance resources and maintain grid frequency, allowing generators to ramp up and down instantaneously. It's used primarily to correct short-term changes in electricity use that could impact grid stability. This component carries a market-based risk that can be hedged. Pricing is determined by usage patterns.

Synchronized/Spinning Reserve is a charge to allow generators and demand-response resources that have the capability to ramp up within 10 minutes to balance generation resources. It's used to supply power if the grid has an unexpected need for additional generation resources on short notice. This variable carries a market-based risk and pricing is determined by usage.

Day-Ahead Scheduling Reserve, which is also known as non-spin reserve, is a fee that allows generators and demand-response resources that have the capability to ramp up within 30 minutes to balance generation resources. It's used to ensure that generation and demand-response resources can meet reserve requirements on a forward basis. This variable carries a market-based risk and pricing is determined by usage.

Operating Reserve is a charge that helps deliver adequate operating reserve by providing spot-market support, ensuring pool-scheduled generation, and making certain demand resources are guaranteed to fully recover their daily offer amounts. Day-ahead operating reserves are assessed on all day-ahead load schedules. Real-time/balancing operating reserves are assessed on deviations between day-ahead and actual usage.

Pricing depends on zone, product type, and usage. In all cases, day-ahead operating reserves are much less volatile and less expensive than balancing operating reserves.

Reactive Supply and Voltage Control, from Generation and Other Sources is a charge paid to generators to maintain acceptable voltage levels on the transmission grid. This variable carries a non-market-based risk and pricing is determined by demand.

PJM Scheduling, System Control & Dispatch Service covers the administrative fees associated with the overhead of running the independent system operator. This variable carries a non-market-based risk and pricing is based on usage.

Transmission Owner Scheduling, System Control, & Dispatch Service is a fee paid to transmission owners for operating the transmission system. Pricing is based on usage.

Black Start Service is a fee paid to generators that have the ability to self-start without the aid of the existing transmission grid. Its purpose is to ensure reliable restoration of the grid following a shutdown of the PJM transmission system. This variable carries a non-market-based risk. Pricing is based on demand and varies by zone.

It's important to note that costs for this particular component are expected to change materially starting in 2015. Many existing black start units have announced plans to retire, and PJM is currently seeking proposals to ensure adequate services.

Generation Deactivation/Reliability Must Run is a make-whole payment to generators that have announced intent to retire but are required to remain online for reliability purposes. This variable carries a non-market-based risk. Pricing is based on demand and varies by zone.

Note that with a fixed-price product, GDF SUEZ Energy Resources provides this cost component as a pass-through charge to customers. This delivers customers the benefit of any reduction or elimination of the cost and provides transparency in a component that cannot be hedged. Some suppliers claim to fix the cost of generation deactivation – which, in many cases, is zero – by referencing the Material Adverse Change in contract language. In such an agreement, charges can be billed. However, if those charges are reduced or eliminated during the contract term, the difference is typically not returned to the customer.

Transmission Enhancement Charges cover costs paid to transmission owners for enhancements to constrained areas in the PJM grid. This charge can result in a credit when transmission owners include enhancement costs in their rates. It carries a non-market-based risk that can be mitigated through risk premiums. Pricing is based on demand and varies by zone and customer usage patterns.

GDF SUEZ Energy Resources considers transmission enhancements an ancillary services charge. However, it is not uncommon for a supplier to include this variable as a transmission cost component.

Auction Revenue Rights are entitlements allocated to firm transmission service customers from revenues generated from the annual Financial Transmission Rights auctions. This variable carries a market-based risk that can be mitigated through risk premiums or credits. Pricing is based on demand and varies by zone and customer usage patterns.

Marginal Loss Overcollection Credit is a settlement mechanism for the overcollection of line losses. Locational marginal pricing is set based on the marginal megawatt flowing over a transmission path, but actual costs paid to generators are based on average flow on a transmission path. This variable carries a hybrid of market-based and non-market-based risk that can be mitigated through risk premiums or credits. Pricing is based on usage and is highly correlated with market prices.

Marginal Loss De-rate is designed to avoid double counting of losses on transmission facilities that are included both in the PJM network model and in the utility state-filed tariff loss factors. This variable carries a hybrid of market-based and non-market based risk that can be hedged or mitigated through risk premiums or credits. Pricing is based on usage and varies by zone and with market prices.

Note that this component can be presented by suppliers by lowering the retail adder with the loss multiplier containing the full tariff losses or by lowering the loss multiplier and correspondingly increasing the retail adder.

Renewable Portfolio Standards is the charge to compensate for renewable energy purchases mandated to meet state minimum requirements. This variable carries a hybrid of market-based and non-market-based risk. Pricing is based on usage and varies by state.

Note that some suppliers treat renewable portfolio standards as a separate pass-through line item. In some states covered by PJM, this component is charged directly by the utility.

Transmission Costs

Transmission costs are located in the upper portion of the energy pyramid and can make up roughly 5 percent of the total electricity price. These charges, which are also known as network integrated transmission service (NITS) costs, are collected from load serving entities and paid to transmission owners as compensation for the expense of owning and maintaining the grid.

The component carries a non-market-based risk that can be mitigated through contract language. Pricing is based on demand with zone and customer usage patterns as key factors in determining ultimate costs.

At GDF SUEZ Energy Resources, this variable is handled through a process called NITS balancing. Essentially, if the rate increases or decreases during the contract term, a charge or credit is calculated for the rate difference and billed/credited as a separate line item.

Some suppliers, however, claim to fix the cost of transmission by referencing Material Adverse Change in contract language. In such an agreement, charges can be billed. But if those charges are reduced or eliminated during the contract term, the difference is typically not returned to the customer.

Making the Right Procurement Decision

In the end, there is a lot to think about when shopping for commercial electricity. With a range of variables to consider – from cost components and energy market fundamentals to business cycles and risk tolerance – transparency in pricing offers is essential to building effective energy management strategies.

To support consumers in making clear, confident electricity purchasing decisions, GDF SUEZ Energy Resources created My Energy Navigator, a proprietary decision process designed to simplify energy buying.

Customized energy management plans are created through a three-step process that starts with an initial assessment of unique operating factors, such as key business drivers, budgetary structures, and risk tolerance. A risk certainty profile is then generated specific to your business along with a pricing proposal that fits your company's profile.

This proposal, which includes detailed information on each cost component of the plan, is fine-tuned with the help of a GDF SUEZ Energy Resources representative. Every aspect of the product is considered by exploring different cost outcomes in real time and adjusting various elements of the proposal.

Commercial and industrial customers ultimately benefit by getting the transparency and insight they need to shop wisely and choose a product that best suits their company and their budget.

Before entering into your next energy contract, be sure to consider a supplier like GDF SUEZ Energy Resources that takes the time to understand important business factors, brings clarity to pricing proposals, and helps you build a strategy that makes the most sense for your business.