Demand Trading Toolkit

Technical Report

Demand Trading Toolkit

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REPORT SUMMARY

The global movement toward competitive markets is paving the way for a variety of market mechanisms that promise to increase market efficiency and expand customer choice options. Demand trading offers customers, energy service providers, and other participants in power markets the opportunity to buy and sell demand-response resources, just as they now buy and sell blocks of power. EPRI's Demand Trading Toolkit (DTT) describes the principles and practice of demand trading and outlines how market participants throughout the electricity value chain can take advantage of this innovative technique to survive and prosper.

Background

As many energy consumers and suppliers in the United States are painfully aware, price volatility, energy shortages, and other difficulties have all too often plagued transitioning power markets. In part, these problems have been caused by inadequate price linkages between wholesale and retail markets. Because spiking prices from constrained wholesale markets do not reach the vast majority of end-use customers in real time, balancing electricity supply and demand can be very challenging at times. Through demand trading, customers' price-responsive demand reductions can be effectively brought to the marketplace to increase market stability. Demand trading builds on demand-response approaches, such as voluntary demand-bidding programs, curtailment options, and real-time pricing. It then provides an avenue for offering these demand-response resources in regional power markets through a variety of market tools such as futures and options.

Objective

- To promote a common understanding of demand-trading concepts and terminology across participants in power markets.
- To arm the electricity industry with tools that will place demand-response resources on an equal footing with supply-side resources.

Approach

The project team combined two decades of expertise in demand response with recent experiences of market participants involved in demand-trading programs. The effort established basic principles for open electricity markets, provided tools that address the mechanics of demand trading, and proffered a vision of how this approach can be made more effective in the future.

Results

The DTT establishes a platform for practicing demand trading in evolving power markets. It showcases the tools used to manage risk in other competitive markets and how they can be applied in the electricity industry. It then details how demand trading can be integrated into

electricity market structures, including how demand-trading tools can parallel their supply-side equivalents. The DTT also summarizes recent experience in this discipline, into the Ten Commandments of Demand Trading:

- Strive for market efficiency
- Be open about price
- Strike liquid agreements
- Quantify risk premiums
- Educate customers about programs
- Test customer-specific capabilities
- Educate customers about markets
- Make verification and settlement intuitive
- Keep procedures computationally inexpensive
- Keep procedures fair to each customer

EPRI Perspective

With the increased openness of electricity markets, the trading of customer demand response promises substantial increases in market efficiency and stability. By providing a key link between wholesale and retail power markets, demand trading can put demand response on a more equal footing with supply-side resources. Fully reaping these benefits, however, will require a reorientation of thinking about roles in the electricity value chain and a focus on the development of expanded choices for electricity customers. Those organizations that develop early experience with these new roles and new customer options should be in the best positions to benefit from this innovative market mechanism. In addition to the DTT, EPRI has developed the Load Management DataBase to provide further information about the new breed of demand-response programs being offered. This web-based system offers convenient access to information on a wide range of programs, including descriptions of program designs, sponsors, impacts, incentives, technologies, and other key parameters.

Keywords

Demand trading
Demand response
Market-driven load management
Price response
Customer service options

EXECUTIVE SUMMARY

The advent of deregulated wholesale electricity markets and the penetration of market forces into retail electricity markets have increased the opportunities for financial gain. One of these opportunities is demand trading, which represents a key tool that can advance one of deregulation's principal goals—customer choice. Customer choice in this setting goes beyond simply being able to choose among different suppliers. It provides customers the means to reduce their energy costs by bidding their ability to change their electricity demand characteristics into energy markets as an alternative to supply. This practice offers customers a proactive role in energy markets and provides a greater ability to affect the ultimate economic variable in competitive markets—*price*.

Everyone knows the basic law of supply and demand. When supply increases (at any given demand level), prices eventually fall and demand increases to intersect at the new point of equilibrium. When supply decreases, prices rise. Despite the fact that regulatory models and other factors have inhibited the transfer of price signals to electricity customers, when given the proper price signals customers can and do change their electricity buying habits. This idea is the basis for demand response programs.

In the past, customers have generally been offered one of three demand response options:

- Curtailment (where the customer had to respond to an explicit request)
- Interruptible (where the customer let the energy company curtail their energy use directly)
- Time-sensitive pricing (where customers were sent advance price signals)

In 1999-2001, many energy companies designed new and innovative demand response approaches. Because traditional long-term bilateral agreements were being replaced by energy trading, the newer demand response programs were modeled after wholesale trading mechanisms. Customers were being offered price signals to reduce demand in return for a share of the benefits derived from that reduction in regional power markets, not just on traditional reliability concerns.

The result was that customer electricity demand response was now being traded. The seller was now the customer, able to reduce demand, and the buyer had become the counterparty who saw economic or reliability benefits in purchasing that resource. It was also resold into regional power markets, potentially for resale to others. Customer demand response was starting to look a lot more like the supply side.

Despite these gains, there have been major obstacles to the implementation of demand trading. For example, there have been nagging doubts about just how real the demand response is and how accurate customers are in their pledging to reduce loads. Just like all other commodities as they were first traded, the acquisition and market clearing mechanisms were a bit clunky and inefficient. In addition, the regulatory models stymied a clean break from traditional regulated supply to free market models. Customers were offered a safe place to hide while retail energy markets adjusted to newly discovered price risks. Innovation was impeded by the regulatory attempt to protect customers, rather than permitting the free market to do that over time.

There are also intrinsic delays in the transition to an open, competitive market. One of these market issues is the lack of a common language among customers, traders, energy providers, utilities, and others in the electricity value chain. The translation of trading instruments into everyday terms and the formal translation of customer demand response abilities into standard trading formalisms will be essential if demand response resources are to be traded against supply on an equal footing. Building understanding across this language gap is one of the key goals of this Demand Trading Toolkit (DTT).

Another goal of the DTT is to demonstrate how demand response can be moved from one of the last resources in the dispatch stack (where it is generally found now) toward a fully competitive alternative to supply in the minds of all market participants. For the foreseeable future, this goal will require enhancing the efficiency of transactions across a value chain that is still a bit unclear and changing. Over the longer term, retail markets will move toward greater competition and transparency, paving the way for an expanded array of demand trading agents and approaches.

The DTT also discusses four goals in designing a open, competitive trading model and how achieving these goals can facilitate the development of demand trading as a resource. These design goals are:

- **Efficiency:** Economists describe this as the ability for buyers and sellers to easily find each other, come to terms, and transact. Today's end-use electricity customers probably have only one buyer for their demand response capabilities. In the future, more market-based demand trading among many market players (even customer to customer) will be implemented, leading to greater efficiency.
- **Price (and Value) Discovery:** Today's single-buyer model for demand trading drastically limits price discovery. Over the long term, the development of open protocols and standardized, tradable agreements will enhance price discovery.
- **Liquidity:** The ability to convert the transaction to cash is an essential element in all commodity markets. Economists call this fungibility or the tradability of a commodity because it can be readily converted into buying power or cash.
- **Risk Premiums:** The identification and appropriate transfer of physical and financial risks for premiums is the fourth critical sign of an open, competitive market. Price protections are offered and traded in structured transactions in sufficient volume and according to reasoned actuarial data so that they can be guaranteed. Counterparties freely enter into and exit agreements (forwards and options) without fears associated with performance terms and financial accountabilities.

In most competitive markets, business risks are naturally shared by counterparties—those who see the opposite point of view about price movements. For example, consumers fear high prices and producers fear low prices. These views are central to the development of successful demand trading models. Market counterparties can strike agreements with customers regarding these price risks by shifting them using real-time pricing (RTP) or sharing them using calls, puts, and quotes. Call agreements are the closest analogy to the traditional curtailment strategy. However, as this report demonstrates, curtailments have not mirrored the correct trading design. Puts—where a customer can offer to take electricity at an above market price, but below that customer's perception of a fair price—is another natural counterparty arrangement. Offering customers a quote for what their demand reductions are worth and consummating a trade is at the very heart of today's voluntary agreements. These all have trading parallels on the supply side. The key question now is how they are valued and implemented in the energy company portfolio. If the energy company's portfolio is too small to trade directly into markets, they should consider aggregating that portfolio with other regional players or agents.

Managing the customer and trading interfaces for demand response is completely different from the supply side. With few exceptions, it is not the phone, fax, and Internet trading platform business used by supply side trading. Demand response is more about building end-use customer relationships, educating them about their load shape flexibility, designing effective programs, and managing customer participation. These processes are neither cheap nor easy.

A key factor in the success of any demand-trading program involves adequate customer training. Points to consider in such a training program include:

1. **Educate customers about programs:** Customers do not speak the trading language and are easily confused and disappointed as a result. Keep all structured programs intuitively simple, use plain English, and limit the number of choices.

2. **Educate and test customer-specific capabilities:** Customers who learn how to respond to these agreements perform well over time. Run readiness tests to help customers develop easy procedures to follow and understand their capabilities.

3. **Educate customers about markets and relationships in markets:** Most customers do not understand regional energy markets and the trading and risk management challenges they present. This lack of understanding can lead to customers assuming that the energy company is not telling them the whole story.

Additional key issues for demand trading involve the measurement and verification of a customer's demand response. There are some common models in use, but they are flawed for certain customer load shapes. For example, some customers might unfairly benefit from claimed demand response actions and some might actually game the situation assuming the energy provider wouldn't notice or challenge them. Measurement and verification protocols should have these attributes:

1. **It is intuitively appealing:** Averaging the previous two weeks of non-event days to set a performance baseline has this appeal. However, its accuracy is not dependable for customers with significant weather-dependent loads.

2. **It is computationally inexpensive:** Data requirements to weather-correct loads are potentially costly and the complexity of the analysis baits customer scrutiny. It is easy to

spend more time on verification and discussion about weather corrections with customers than the event is worth.

3. **Each customer accepts it as fair:** At the end of the day, the goal is to strike a bilateral agreement, not play a game of cat and mouse. Not all customers are the same. Not all measurement, verification, and settlement procedures need to be the same.

Based on measurement and verification results, most energy companies correct the benefits paid to customers if the demand reduction achieved is significantly different than what was pledged. Recent experience has shown that individual customer pledges versus actual performance can be a bit erratic, but that aggregated performance improves quickly when 10 or more customers are in the mix.

Customers and program sponsors often find that rapid information feedback during a demand response event can be helpful. This feedback can be accomplished by interrogating meters and verifying customer performance during events. While potentially too expensive for smaller customers, larger customers should find this information valuable and be willing to pay for the enhancement. If they won't, carefully consider whether these customers are going to participate in the demand trading program anyway.

When contemplating the future of demand trading, one must look beyond the current incomplete deregulation patterns that characterize current electricity markets. Commodity trading evolves along broad categories: resource development, agent relationships, exchange liquidity, and arbitrage trading. Customer demand trading resources expand through technology and information. These resources increase customer demand trading elasticity. But, they also require the acceptable standardization of trading instruments and parties who can trade them. Because most smaller customers would prefer to outsource their opportunity, trading will also require permissible agent relationships. Demand trades will eventually be graded and valued along a continuum, much like stocks and bonds. Some will be AAA rated—better than some generators because they are already delivered and will have environmental virtues as well.

Depth and liquidity of demand trading markets will only occur when the financial derivative instruments of risk management can be deployed as well. As the underlying actuarial data are understood, there will emerge a spectrum of price and risk differentiated products and services in the market. Demand trading aggregation will permit risk mitigation and rightfully deserved long-term premiums.

Finally, agents and the act of arbitrage will play a valuable role in demand trading as it does in all other commodity markets. At the moment, only the individual energy providers decide what the resource is worth. Customers will eventually look at multiple offers and decide which one best fits their abilities or desires for risk. Similarly, customers under real-time pricing programs with undesirable wholesale price exposures will find counterparties (surrogates) to take their place. This idea is becoming easier with Internet exchanges, but most of these exchanges are many-to-one models with no standardization of demand trading resources. This situation will need to evolve to a many-to-many interchange in which all market players (even customer-to-customer) can freely trade with one another.

Today's methods for trading electricity in open markets are inefficient and in transition. We shouldn't be too critical because these methods are still in their infancy. In today's markets, frustration can be so great that energy parties simply leave the table and do not play. However, those who play today will be better prepared to shape the path towards the future and will have learned a great deal about counterparties and their perspectives in the interim.

In this interim, an organization considering demand trading opportunities should consider whether their plans and actions are progressing towards open market models:

- **Open market interfaces and structured transactions:** Building the optimal customer demand response portfolio requires transactions that are tradable to multiple parties. As such, they require counterparty acceptability and they must be fungible (convertible to cash or the equivalent in financial transactions).
- **Open trading protocols:** Liquidity in demand trading transactions will require standardization, protocols, and performance assurances. These transactions should trade with price and value discovery, along with any other determinants that counterparties might deem valuable.
- **Open information protocols:** Markets only flourish when there is complete confidence in counterparty performance. Open information protocols with appropriate security constraints (so that private information stays private) can assure market participants of being paid in a timely manner for what they did and didn't do.

Some might feel that the path toward an open, competitive market for demand response is too clouded with uncertainty, the restrictions too prohibitive, or that they do not have the resources to acquire and maintain customer participation. Others might view the trading of customer demand response as the "killer app" of energy deregulation (following the analogy of a "killer app" for computer adoption of the 1980s) and feel that these price-responsive, demand trading customers are the best ones to acquire or retain as energy markets move towards open, competitive models. We believe that the latter view is the best long-term strategy.

As electricity markets open, the trading of customer demand response promises substantial increases in market efficiency by providing a transparent portal between wholesale and retail power markets. Reaping these benefits, however, will require a reorientation of thinking about the roles in the electricity value chain and a major focus on the development of new options for electricity customers.

For those who believe that demand trading is a critical element in the success of open, competitive retail energy markets and are intent on pursuing this discipline, we propose the following Ten Commandments of Demand Trading:

1. **Strive for market efficiency:** Provide customers with easy choices and position your organization as their preferred choice.

2. **Be open about price:** Don't fear customer knowledge of price. Become the customer's agent to get them the best value (price plus bundled services).

3. **Strike liquid agreements:** Move towards arrangements where resources can be acquired, aggregated, and traded against supply alternatives.

4. **Quantify risk premiums:** Today's customers are just now becoming aware of price and volume risks. While they are learning to deal with these risks on their cellular phone plans, the electricity industry has a long way to go to educate customers about volume and price risk.

5. **Educate customers about programs:** Keep all structured programs intuitively simple, use plain English, and limit the number of choices offered to customers.

6. **Test customer-specific capabilities:** Run readiness tests to help customers understand their demand reduction capabilities and develop easily implementable procedures.

7. **Educate customers about markets:** Help customers understand regional energy markets and the trading and risk management opportunities and challenges these markets present.

8. **Make verification and settlement intuitive:** Trading requires bilateral confidence. Whatever works for you and your customers can be made to work.

9. **Keep procedures computationally inexpensive:** Procedures to weather-correct loads and settle accounts must be simple to implement.

10. **Keep procedures fair to each customer:** At the end of the day, the goal is to strike a bilateral agreement, not play a game of cat and mouse.

Customer demand response is a precious resource that can be traded against supply. Seize the moment—customers are eager to consider your offers.

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1 INTRODUCTION AND OVERVIEW OF DEMAND TRADING

Everyone who has ever studied economics remembers the laws of supply and demand with regard to pricing in open, competitive markets. When supply increases (at any given demand level), prices eventually fall and demand increases to intersect at the new point of equilibrium. When supply decreases, prices rise. Regulatory models tend to pervert that process and have long been criticized for artificially imposing higher than necessary prices when supplies are robust.

That fact fueled arguments for deregulation of electricity in the early 1990s with promises of 20 to 40% price reductions. Unfortunately, as the wholesale electricity markets opened along the way, the incentive to build both additional supply and transmission capacity was inadequate to maintain ample reserves in several areas of the country. The results included substantial wholesale price spikes in each year from 1998 through 2001 and the potential for spikes on into the future. Meanwhile, retail customers were largely insulated from these spikes through regulated retail rate structures. As a result, demand was insulated from price.

This inadequate transfer of price signals from wholesale to retail markets, made painfully obvious during this period, pointed to the need for new models in customer price awareness and a means for forwarding that price in some useful ways to customers so they could respond to it (rather than merely see the effects over time). Historical rate-making practices were not always sending the right signals. Traditional electric utility rate schedules might attempt to send overall seasonal and typical daily price signals, but these price-forwarding mechanisms were hard for customers to use because most of them did not know nor understand their pattern of energy use. Plus, these rate schedules might not reflect regional power markets.

In fact, many utilities saw wholesale price spikes when there were no “native needs” for customer demand reductions at all (they were not at their peak demand level—other regions of the country were). Even real-time pricing models were often based upon the native generation bid stack and were completely out of line with regional wholesale prices. Many of these pricing models would signal customers to reduce loads at times and at prices that were calculated to be high, avoiding costs using regulatory models. At the same time, regional markets were at a much lower price. Therefore, these pricing models would signal customers to use power freely at the same time regional prices were spiking.

As this economics illustration implies, price signals affect demand, but only if they are made available in time to affect buying behaviors. Receiving a bill at the end of the month is one form of price signal, but that method of forwarding the price to customers has an intrinsic lag. The best forwarding mechanism would be where the customer knows the price ahead of time and chooses to buy at that price (as it is routinely accomplished in wholesale markets). Retail markets can perform this price-forwarding mechanism. Most energy companies using it call it real-time pricing. These forwarding methods are essential elements to making a market efficient—one where buyers and sellers easily find each other and can come to financial terms.

Innovative demand-response price-forwarding models were developed in 1999 based upon trading mechanisms to improve this efficiency and bring new demand-responsive resources into the market. Customers were being offered prices to reduce demand based upon a share of the benefits of that reduction in regional power markets, not just for reducing demand due to traditional reliability concerns. But, the customer's existing load-serving entity didn't always have an interface to the wholesale market, and in fact might be under full requirements agreements from their generation sources. Even though trading what you don't need to someone else who does need it is one of the oldest forms of commerce, those agreements were outlawed in some cases, and financial settlement methods were potentially contentious. So they just didn't happen to the extent that they could. After all, the seller wants to be paid by the buyer. That sounds so simple in everyday commerce, but is not easy at this time in the electricity trading business. Ownership of the resource potentially being traded still resides largely in the hands of the load-serving entity in regulated energy markets. Even in open retail markets, customers might not be able to sell their demand-response capability to anyone.

Nevertheless, many electricity companies in the United States moved towards trading models in their demand-response relationships with their retail customers. They offered customers seasonal call agreements (mirroring the call agreements in their power markets) and offered energy-only price-sharing models. Educating customers to this new language and introducing terms and conditions that broke from previous understandings (and misunderstandings) was costly. But, the high prices seen in wholesale markets awakened customer interest. They wanted a piece of the action, and many wanted to be removed from their curtailment agreements anyway, because curtailments were now being used more often than customers ever anticipated.

The result was that customer electrical demand response was now being traded. The seller was now the customer, able to reduce demand, and the buyer had become the counterparty who saw economic or reliability benefits in purchasing that resource. It was also resold into regional power markets, potentially for resale to others. Customer demand response was starting to look a lot more like the supply side. A growing number of people no longer viewed customer demand as merely a "load to serve." It was increasingly viewed as a resource to be managed, whose time pattern could respond to combinations of price signals, controls, and information.

Despite these gains, there have been major obstacles to the implementation of demand trading. For example, there have been nagging doubts about just how real the demand response is and about how accurate customers are in their pledging to reduce loads. It is very challenging to measure something that didn't happen.

Just like all other commodities as they are first traded, the acquisition and market-clearing mechanisms were clunky and inefficient. Customer meters might still be read only at regular monthly intervals. Regulatory cost-recovery mechanisms might still prevent full economic benefits of demand reduction because these credits are netted against all wholesale power purchases and then simply passed on to customers (in a fuel clause adjustment) without providing benefit to those who are doing all the heavy lifting to make this possible.

While it's uncertain just how much demand response would have made a difference in the price spikes in several markets in the 1998 to 2001 time frame, there are certainly very few now who would argue against it. It would have made a significant difference. As evidence of the significance and value of demand response, generating companies in New York state requested recovery for anticipated lost revenues as the New York Independent System Operator (ISO) launched its demand-response program.

Demand response can be and is now being shaped by the evolution in these wholesale and retail market forces. Those managing this resource well in the evolving energy markets are also shaping customer perceptions of who they are and this will influence whether the customer will stick with them as the customer's competitive choices increase. Those managing the resource well are also shaping regulatory and legislative perceptions of whether they are merely doing it for self-gain and/or the well being of all their customers. Those managing the resource poorly are decreasing the price-responsive qualities of this resource and potentially damaging all future relationships with customers. Others simply sit back and wait for clear approvals or direction, thus missing an opportunity.

As wholesale competition proceeds in the United States and around the world, electrical demand response is transitioning from regulatory models to trading formalisms. Energy companies facing these changes, along with demands for greater customer choice, will have to rethink their traditional load management mechanisms and consider movement towards traded instruments. This task is made a bit more difficult by the language barriers between traditional customer-facing organizations and trading/wholesale market-facing groups. They work with a different language and think in somewhat different terms. Customers seldom speak the trader's language and terms such as "liquidated damages" have a less than friendly ring to them. Translation into everyday terms and the formal translation of customer demand-response abilities is essential on both sides so all parties can have a common understanding and confidence in the demand-response resource. That is one of the key goals of this Demand Trading Toolkit (DTT).

Another goal is to move demand response from one of the last resources in the dispatch stack to a fully competitive alternative to supply in the minds of all market participants. Doing so requires efficient transactions across a value chain that is still a bit unclear and changing. Value is only achieved when transactions occur. Creating those transactions requires counterparties at the beginning and the end of the value chain: retail customers and wholesale markets. In between, there are regulated and unregulated entities each trying to find value. Unfortunately, the rules of engagement are far from settled and are disparate across the United States at this time. Someone has to work with customers, someone probably has to aggregate their demand-response capabilities, and someone has to bring that to the market, or use it to avoid buying in the market. The key element is creating a tradable agreement across the value chain. That is another key goal of this DTT. But, that agreement has to be attractive to all parties—not an easy task!

This DTT illustrates how customer demand-response capabilities fit into the resource mix, what the risk and reward profile looks like in relation to traditional supply-side forward and option agreements, and how customer aggregation strengthens the confidence in and value of demand trades by illustrating the successes and challenges of measurement verification and settlement. Much of this proof of value comes from the operation of dozens of demand-trading programs in the United States and around the world. Customers are proving they are often a lower cost alternative to supply. They are also demonstrating that they can discipline the wholesale market when inadequate generation is available and can lower final settled prices on supply-side auctions. This is one of the key attributes of an open, competitive market—one that is desperately needed now to move beyond artificial constructs (such as price caps).

Most of us understand price risk: the need to be able to plan and budget for the future, and be a good steward of corporate profitability. Taking on too much price risk can at times seem prudent because insurance always looks like an expense when times are good. Unfortunately, you can't go out and buy fire insurance when your house is on fire. So, most of us purchase an appropriate level of risk protection. Retail energy markets now are exposing customers to an awareness of this price risk, what was actually "bundled in" the old regulatory agreement. The second risk for energy purchases is volume risk: the amount you buy. Given that high-priced periods of time tend to be at the extremes of weather, volume is up as well. Therefore, the risks compound, because the price paid will be higher and buyers will have to buy a greater amount at the high price.

Mature retail energy competition will require the assignment of dollar values (monetization) to price and volume risks, and that counterparty accountabilities shoulder those risks. In the interim, the incomplete and immature market mechanisms shift risks before counterparties even know they are bearing them. In some cases, when those risks do surface, it is simply too late or politically impossible to shift them to the rightful counterparties or to change pricing to reflect them. An unfortunate outfall is that load-serving entities and their counterparties can and, in some cases, do go bankrupt. In other cases, the rewards for shouldering those risks provide windfall benefits for one season only, and then disappoint counterparties to the point that they abandon such agreements. For example, the price caps in the Western States Coordinating Council (WSCC) in the United States are so low (approximately $100 per MWh at the time this report was written) that they effectively blunt the opportunity to find value in shifting demand response. Of course, they are posing similar risks on the supply side, potentially discouraging the development of generation resources as well.

At this time, it appears that the power industry will stay in this incomplete transition to full retail deregulation for some time. In addition, the emergence of regional transmission organizations (RTO) out of ISOs and the rules for demand-response participation in energy markets are in flux. This uncertainty will impede many organizations from pursuing the development of demand-response resources, especially at times when price caps limit the value of demand-response economics. However, forward-thinking organizations that build customer relationships during this transition period and promote early education about the risk-reward possibilities will have an advantage as demand response becomes a more market-oriented resource.

Managing the customer and trading interfaces for demand response is completely different from the supply side. With very few exceptions, this is not the phone, fax, and Internet trading platform business like the supply side. This is about building end-use customer relationships, educating them about their load shape flexibility, designing effective programs, and managing customer participation. This is neither cheap nor easy and generally requires aggregation to participate effectively. This DTT lays out all the steps and protocols required.

Where Are We Going?

Will electricity ever be traded in open, competitive retail markets? Some might argue that we will only see wholesale markets follow this model and that we will never successfully get retail electricity customers into that market. Others might argue that we should re-regulate the wholesale market until there is adequate transmission and generation availability. Regardless of one's views on these issues, in discussing the benefits and drawbacks of markets for demand trading, it is valuable to first define what constitutes an open, competitive market.

Those attributes have long been known and implemented by the New York Mercantile Exchange (NYMEX) and other commodity exchanges around the world. They are proven and important guidelines for our discussion of demand trading. We all must keep these in mind as we manage during the transition to full retail competition. Trading demand response has been valuable even in historic regulated models, although we didn't call it that, because the trade was simply from the customer to one buyer, stopping right there. Wholesale electricity trades a multiple of times before the final buyer takes delivery. Demand trading will become even more valuable over time in open wholesale markets, and offers the potential for the development of a whole spectrum of products that can create value in open retail markets.

The wholesale electricity markets in the United States are well on their way towards this goal of being open, competitive markets. In such markets, end-use customers will eventually be able to participate with their demand response as an alternative to supply. Keeping this in mind will help to ensure that demand trading is implemented on sound footing. Therefore, before going further, consider the endgame and the appropriate design goals in any open, competitive trading model:

- **Efficiency:** Economists describe this as the ability for buyers and sellers to easily find each other, come to terms, and transact. Today's end-use electricity customers probably have only one buyer for their demand-response capabilities. If the buyer sees little value in that response capability, they might not have much incentive to trade that to others in the market that would like to buy it. The constituent elements needed to enable efficient demand trading are the formation of tradable agreements (Section 3) and acceptable measurement, verification, and settlement methods (Section 5). Terms and conditions must be understandable among counterparties to make the transaction repeatedly useful, and aggregation of individual customer demand-response resources is probably essential to create sufficient block sizes for trades (typically 25 MW each hour in most regional electrical systems in the United States).
- **Price (and Value) Discovery:** Today's single buyer model preempts price discovery, even in situations where customers have access to wholesale market information. The buyer (that is, the load-serving entity) might not have regulatory permission to trade the resource in wholesale markets. Or, the potential buyer might not have a supply/demand imbalance situation where trading customer demand resource would have financial benefit. Plus, regulatory fuel clause agreements might blunt the value proposition completely by automatically transferring any net benefit back to all other customers and away from bottom line benefit. While aggregation of customer demand trades might eventually vie for an equal standing against supply-side resources, the value of that resource can be best assessed by what someone will pay for it. That requires a market model that permits price discovery. Even though market participants might argue that they attempt to do that today, many of the

mechanisms are arcane and inefficient. Continuous activity in commodity arbitrage is a clear sign of price and value discovery. Most demand trading currently only occurs when massive price differences occur between wholesale market prices and retail price signals.

- **Liquidity:** The ability to convert the transaction to cash is an essential element in all commodity markets. Economists call this fungibility or, quite simply, the tradability of a commodity because it can be readily converted into buying power or cash. For example, we all carry currency around in our pockets with full confidence that it can be used in everyday commerce. Customer demand response is far from fungible in today's energy markets, but things are moving along. Fungibility of any commodity depends upon counterparty credit and confidence in market-clearing mechanisms. It also requires that offered prices are paid, and in a timely manner. Plus, positions can be exited and substitutes found through counterparties who are willing to buy or sell positions to reflect changes in plans. Today's demand-response resources are quite illiquid. Liquidity is severely restricted with only one buyer and the restrictions mentioned above, as well as regulatory restrictions on the market-access retail customers have to offer their demand response to anyone interested in buying it. While the restrictions are understandable in today's regulated markets, they limit the resource and innovation around the acquisition, aggregation, and transactions associated with demand response. There will come a time when markets are truly open and competitive, when customer demand response can be aggregated and sold to anyone willing to pay according to acceptable terms.
- **Risk Premiums:** The identification and appropriate transfer of physical and financial risks for premiums is the fourth critical sign of an open, competitive market. In such a market, price protections are offered and traded in structured transactions in sufficient volume and according to reasoned actuarial data so that they can be guaranteed. Counterparties freely enter into and exit agreements (forwards and options) without the fears associated with performance terms and financial accountabilities. The current interim situation for the electricity industry frustrates many possible counterparties with restrictions on who can aggregate, buy, sell, and settle demand trades. Interestingly, the risk profile of demand response is quite different from that of a generator in that it is already delivered into the zone and has no losses for transmission and distribution. And, due to the aggregation of a diverse customer portfolio to get to the 25 MW or larger block, the failure to perform risk can be lower than an equivalent generation block. Nevertheless, the current market mechanisms fail to either reflect this benefit or offer the efficient clearing of risk valuations. NYMEX and other exchanges guarantee the performance of the agreements (by forcing participants to cover their positions with margin requirements, the same way stock transactions are covered).

Section 2 of this manual discusses the current resources in trading demand response in regulated retail interfaces along with a history of how this resource evolved from prior vertically-integrated energy companies operating without open, competitive wholesale markets. These closed-market regulatory models encouraged (or required) the energy company to accept the obligation to serve in exchange for allowable rate-of-return ratemaking. They also insisted on prudence in the assembly of resources to meet the aggregate of customer needs and had the right to disallow any costs deemed imprudent. As a result, energy companies entered into bilateral and sometimes long-term agreements with other regional energy players to meet their planned and emergency needs. Customers in this world were generally offered one of three demand-response options: curtailment (where the customer had to respond), interruptible (where the customer let the energy company curtail their energy use directly), or time-sensitive pricing (where customers were sent advance price signals).

Demand trading under this regulatory model involved many-to-one transactions. The load-serving entity was the only buyer for the resource. Most of the customer agreements reflected capacity agreements in the regional markets and were deemed prudent if the source of customer demand response was less expensive than the capacity agreement that it displaced. The customer was a price-taker only and there was no “bid-ask spread” on that price—it was a “take it or leave it” proposition and the offered price did not depend upon whether the customer turned off lights, ran a generator, or took a maintenance day. In addition, there were no open protocols for information flow about the transaction itself. The serving energy company could simply deem the customer’s performance as acceptable (as in residential direct load control situations), or read a meter to verify performance.

A Possible Endgame

It seems appropriate to jump right to the possible endgame of demand trading—what would it look like if retail energy competition was robust and efficient and interfaced directly to an open, competitive wholesale market? There would be many potential buyers for the customer’s demand response, and some might even be looking for specific types of resources due to their environmental benefits. Some of the agreements would have monthly terms for number of calls, hours of duration, and exercise prices. There would be week ahead, day ahead, day of, hour ahead, and ancillary services transactions. Some customers might prefer to bid into the market while others might choose to select from multiple offers (individual hours at a high price, blocks of hours, some with liquidated damages, and others without liquidated damages).

Customer demand-response capabilities would be aggregated and traded as full competitive alternatives to supply with open protocols for measurement, verification, and settlement of the transaction. Customers in this model would discipline the market and act as price-makers rather than price-takers. Customer demand response would move from a “last resource” at the top of the supply stack (even though it was available at a lower price than options below it in the bid stack) to its rightful place in the stack. Under this model, a customer under a retail real-time pricing (RTP) agreement could buy demand response from others to take their position in the market if that was more desirable or cost effective for them. Once again, aggregation provides real value to all parties. Under this model, risks would naturally emerge into a spectrum of price-risk differentiated products and services, and innovation would naturally occur without regulatory intervention.

The current market falls well short of these endgame competitive wholesale and retail markets. The speed at which we transition to these competitive demand-trading markets will depend on deliberate and creative actions. In the meantime, customers are facing a confusing set of messages, causing many of them to become disenchanted. In some regions, too many options are being offered and price caps are inhibiting price signals (for example, California as of 2001). In much of the United States, the summers of 2000 and 2001 had no price spikes of note and the new voluntary demand-response programs simply didn’t operate. This disheartened customers that signed up for voluntary demand-response agreements (where they would have been paid a portion of the wholesale market), who now wanted a piece of the action instead of what seemed like a lower, sure price reduction. In addition, some customers who had participated in curtailment or interruptible agreements in 1998 and 1999 abandoned them and did not go onto voluntary agreements, because the number of events experienced was far higher than their comfort level or value received. They wanted to know that they could buy power on a fixed price schedule.

The net result is that the demand-response resource in the United States is actually declining at this time. Few seem to realize just how serious this is. When customers leave agreements, it is more difficult to reacquire them, and it might take a higher price to do so. If the entry of creative market approaches fails to reverse these trends, customers might soon become "hard of hearing" when it comes to demand-response programs.

Customer demand-response elasticity (the degree to which customers will reduce energy use in response to price signals) can be developed and is far from static. Information, education, and enabling technologies can be combined to achieve an impressive portfolio of options. Creative market entrants find that they can increase the price-responsive behavior and lower acquisition costs per MWh through this. But, the customer has to engage the opportunity or allow others to harvest the resource. This is far from easy or inexpensive in today's markets.

Demand-Trading Dimensions

Any organization considering demand-trading opportunities should consider whether their plans and actions are progressing towards open market models along the following dimensions:

- **Open market interfaces and structured transactions:** Building the optimal customer demand-response portfolio requires transactions that are tradable to multiple parties. As such, they require counterparty acceptability and they must be fungible (convertible to cash or the equivalent in financial transactions). Crafting self-serving agreements (where most of the benefit is retained by the energy company rather than shared in an open way) might optimize the resource in the short term. However, such approaches might frustrate the transition to open, competitive models because either they are not useful to the wholesale market traders or they disengage the customer over time. Market price signals should eventually be able to replace regulatory signals in these agreements.
- **Open trading protocols:** There are a few large customers who are very capable of shaping their demand and for whom energy prices are a large part of their bottom line, who will interface with the wholesale market directly. These customers probably interface with the wholesale markets now and whatever resource they have has been captured and actively competes today against supply. However, most customers are not going to try to directly interface to wholesale energy markets with their demand-response capabilities. Most will want someone to act as their agent, and that party is quite likely to aggregate these customers into trading blocks. Liquidity in these transactions will require standardization and performance assurances similar to the futures and options trades on the NYMEX. This standardization is effectively the commoditization of demand response as the mirror of supply agreements—firm with liquidated damages, non-firm, and as available. These transactions should trade with price and value discovery, along with any other determinants that counterparties might deem valuable.

- **Open information protocols:** Markets only flourish when there is complete confidence in counterparty performance, especially confidence in customers' demand reductions. Real-time monitoring of customer loads, a mechanism for quickly validating demand response, is too burdensome and expensive for most customer demand-response situations. Open protocols with appropriate security constraints (so that private information stays private while aggregated confirmation of demand response can be conveyed to appropriate counterparties within a useful time frame) can assure market participants of being paid in a timely manner for what they did and didn't do. Customers responding to hourly price signals can rely on interval metered data read within the hour, while those bidding into ancillary services markets will need near real-time demand-response metering. In most cases, the information from the individual customers will require aggregation and open communication protocols to assure market participants of performance and enable settlement. Prices offered to any one customer might ultimately depend upon the quality of the predictability of their load shape changes in response to price, but the financial settlement should not require tedious requests for information and six months to settle.

Some might feel that the path toward an open, competitive market for demand response is too clouded with uncertainty, or that the restrictions are prohibitive or do not have the resources to acquire the customer participation. Others might view demand trading as a key ingredient and feel that these price-responsive demand-trading customers are the best ones to acquire or retain as energy markets move towards open, competitive models.

As electricity markets open, the trading of customer demand response promises substantial increases in market efficiency by further linking wholesale and retail power markets. Reaping these benefits, however, will require a reorientation of thinking about the roles in the electricity value chain and a major focus on the development of new options for electricity consumers.

2
EXPERIENCES TO DATE IN DEMAND TRADING

Customers, energy companies, regulators, and even politicians are all interested in customer demand-response participation. For example, the Federal Energy Regulatory Commission (FERC) recommends the active inclusion of demand response in regional power markets. With all of this apparent positive consensus, why is it that those attempting to produce greater market efficiency through customer price-responsive demand trading often become so frustrated and fail? In part, this is due to the unclear, inconsistent, and changing rules about who can, and in what ways they can, capture this opportunity in today's electricity markets.

Even though the following three steps seem simple, executing them can be extremely difficult, time-consuming, and therefore expensive. Very simply, capturing the value of a customer's demand trade requires three steps:

1. Acquisition of appropriate customer participation (get the right customers signed up for the right types of programs)

2. Execution (requires an appropriate operational information/communications infrastructure) of the aggregated customer demand-response portfolio of participation with an organization that can transact on the aggregate response in the energy markets (consummate the trade)

3. Measurement, verification, and settlement of the transaction repeatedly over time (get people the money they have earned)

Let's take a closer look at each of these steps and see why the current landscape of power markets in the United States is so challenging at this time.

Step 1: Acquiring appropriate customer participation is far from trivial in theory or cheap in practice. In some areas of the country, the existing energy distribution company is ruled out of this relationship [Electric Reliability Council of Texas (ERCOT) and, up until recently, the investor owned utilities (IOUs) in California]. In many cases, an aggregator can only acquire customer demand-trading rights if they serve that customer at retail.

Also, retailers are stymied by the general lack of interest most customers have about choosing an alternative energy supplier in competitive markets. Experience to date has shown that very few customers switch from the incumbent if they are permitted to stay with them. Even those who are assigned to a new entrant (for example, the 300,000 customers assigned to Enron in Pennsylvania) tend to return to their original energy supplier over time.

Finally, when retailers fail in these competitive markets, their customers are generally turned back to the incumbent at some "price to beat" and thereby expose that incumbent to both price and volume risk (because the incumbent is not given a schedule for these returns and is unlikely to have purchased reserves to meet this risk).

Step 2: Executing the demand-trade transaction in today's energy markets is an extremely inefficient process because agent relationships are generally illegal. You can't sell what you don't own, nor sell to an unwilling counterparty. These phrases sound obvious but they are key determinants to the execution of the transaction to produce financial value. Customers generally do not own their demand-response capability. They can release their supplier of the obligation to supply, but they are not reselling that right. Neither can an outsider remarket that right to others, unless specifically entitled to do so (which, at the current time, is only rarely permitted). In addition, counterparties can't be forced to accept the customer's demand trade as an alternative to supply agreements. Plus, the perception of value for the demand trade is governed largely by the perceptions of the buyer, not the seller.

One can argue that much of this is a result of the incomplete deregulation of the electricity markets in the United States, but that is the status of the current markets. One day, customers will be permitted to see multiple offers for their demand-response capabilities and select the counterparty based upon the transaction style and terms best suited to that customer's interest and capability of participation. At the moment, however, customers are only shown the terms and conditions for their existing energy provider's view of the situation.

For example, an energy provider who is fully hedged for supply (that is, they have purchased full coverage for their requirements to serve customers and have no marginal risk for price exposure at peak prices) might not see the value of working with customers to take their demand-response capabilities to the market. In addition, they might not feel that it's worth the time and effort to do so, even if the potential rewards are great because regional markets are seeing price spikes. This is especially true for electric membership cooperatives where the customer is served by a distribution cooperative and the power requirements are met at wholesale through a generation and transmission cooperative relationship.

In these cases, even though member cooperatives might already participate with demand reductions for native, peak load-management programs, these members might not see, nor have economic price signals associated with aggregating demand reductions in response to regional price signals. These regional price signals might be high when native generation is not at peak, and vice versa. While open, competitive markets might be sending clear price signals, the internal generation and transmission (G&T) member systems might not have price-forwarding (or, more correctly, opportunity-forwarding) mechanisms.

Step 3: Measurement, verification, and settlement of a transaction sounds simple enough once the rules are set (that is, baselines, liquidated damages), but even this step has intrinsic problems. Participants want to be paid without argument for the value they produce repeatedly over time. That requires getting to the interval meter at reasonably expedient intervals (usually daily), providing the customer and other market participants with appropriate levels of feedback about actual customer performance to determine true costs and benefits, and getting the transaction into the appropriate billing systems.

These seemingly simple steps can humble the largest and most capable energy companies because they are exceptions to the legacy revenue cycle procedures. As such, they currently are expensive to execute, error (or argument) prone, and tend to lag actual customer participation by one billing cycle at best (and six months or longer in some of the worst situations). Likewise, customers are often left to “fly blind” with respect to their attempts at demand reductions, because information on quantities like electrical load profile baselines are unavailable on the day action is requested. People want to know what benchmark they are performing against, be paid for what they do in a timely manner, and certainly to know how well they performed in enough time to remember what they actually tried to do!

The result of these current inefficiencies and inappropriate market rules is that the demand-response market is largely a squandered resource at this time. Where energy companies are working through these difficulties and getting customers to participate, the execution of the trades with customers produces such clear benefits that the customer starts thinking about other ways they can reduce demands. As a result, the path of progress widens and enthusiasm grows. On the other hand, if the first efforts fail or disappoint either the customer or the market sides of these transactions, forward progress tends to slow or stop. Keep in mind that it is much harder to reactivate a customer’s participation than it is to obtain it initially.

Increasing the customer’s demand-trading capability requires significantly more effort than simply calling another supply-side participant or executing a trade on the market platforms. It requires a relationship between customers and the wholesale energy markets—a fragile and somewhat unnatural relationship because of the differences in perspective and language of interactions. Those who master this relationship will gain a competitive advantage over those who don’t.

Trading Strategy and Time-Domain Perspectives

Where demand trading is being implemented, customers trade their price-responsive capabilities into the market as alternatives to the supply-side in many ways. Interestingly, these trading models answer many of the energy planning and risk management questions on the minds of energy companies today. To understand both the supply-side and the demand-side trades, it is important to know who is running the markets and the time domains they live within.

First, let’s start with time horizons. Imagine a time line that starts with multiyear and yearly plans at the left edge of the scale and ends with the actual bill for an hour’s worth of electricity as it has been produced at the right edge of a time scale. The time zones to the extreme left are planning time zones, and those to the extreme right are called real-time energy markets. Energy trading breaks those zones into standardized blocks. Long-term trades are for an entire strip of months, possibly years, into the future. The trades might be for all 24 hours of the day, or broken into on-peak (the 16 hours of the day starting at 7 a.m. and ending at 11 p.m. from Monday through Friday) and the remaining 8 off-peak hours of weekdays plus weekends. Seasonal trades are consummated in the same manner.

Then, as each season actually approaches, energy companies look a bit closer at their likely customer loads, schedule resources out for maintenance, sell off what they don’t feel they need, or buy what they determine they do need. Because the specific energy needs are weather-dependent in most cases, and the weather is unpredictable and normally quite variable, the specific daily and hourly needs are reassessed about a week ahead and refined even further as the day ahead approaches. At that point, most regional energy market operators (ISO/RTO organizations or their equivalent) require the load-serving entity (LSE) to submit a balanced schedule to them each day, from which they arrange suitable bids to provide reserves to maintain system voltage, frequency and so forth. Many of the activities in these ISO/RTO organizations involve relatively short-term price bids from generators and automated generation control (all of which is lumped under the term *ancillary services*). Through their efforts, final adjustments are made and allocations of the costs of maintaining voltage, frequency, and reliability requirements are assigned.

The following table shows how these vary with time horizons, and who is responsible for their trading agreements in each time domain:

Table 2-1
Time Horizons

Who Plans?	**Load-Serving Entities**				**Both**	**ISO/RTO**	
Supply Choices	Build/ Buy	Forwards/ Maintain	Load Follow	Block Trades	Hourly Market	Ancillary Services	Market Settlement
Time Horizon	Long Term	Seasons/ Months	Month/ Weeks	Days Ahead	Hours Ahead	Minutes Ahead	After Hour/ Month End

End-use customers mirror these supply-side choices in their trading agreements. The only realistic strategic option the typical customer has for mirroring the supply-side build option is an investment in efficiency, because most customer-owned generation cannot compete with baseload supply-side generation. The heat rates and fuel costs simply rule out all but the best cogeneration applications, and most of those applications are large enough to enter directly into power sales agreements with the wholesale market or energy companies (and probably have). Ironically, this conclusion parallels the traditional integrated resource-planning thought process. Only now, the question of value is settled by market forces, not a calculated avoided cost. But, in many cases, energy efficiency might be a lower cost option.

The challenge is to link that investment in a customer's efficiency to the market relationship making that strategic investment. Theoretically, this model works for any compensation relationship where those investing in the customer's energy efficiency can recover at least a portion of the benefit of that investment. The most common proven model today is where third parties strike performance-contracting or shared savings relationships in which they invest in the customer's energy efficiency and are paid out of savings. There are energy retailers who are currently doing this.

Seasonal demand trades could also be offered to customers for weather-dependent loads such as thermal storage for cooling. Where environmental rules permit, customers might even offer seasonal operation of a generator as a trade. However, customers are generally not very receptive to this range of involvement. Most of these opportunities will be captured again by third-party entrepreneurial approaches where the customer turns over the opportunity to them to harvest the economics. Once again, there are energy retailers currently doing this.

As the time period shortens to days-ahead or perhaps a week-ahead, customers can offer to turn things off, take maintenance days, or even shut down completely. These are term trades (trades for a term of time) and are most often offered to customers as “balance of the week” or “balance of the month.” Then, as the time period shortens to days ahead, most LSEs offer fixed price hourly blocks or even the entire on-peak period to customers for their consideration in demand reductions. As the time horizon moves to day-ahead or even day-of, the longest blocks are commonly four hours long, or actual hourly prices are quoted. As the time shortens to a few hours-ahead, LSEs typically resort to their curtailment and interruptible agreements. Direct load controls (controllable water heaters, air conditioners, and remotely operable generators) can be operated by the LSE or may be sold into the ISO/RTO as alternatives to the supply-side generators.

Customer Demand Trades Offer Exceptional Optionality

As indicated earlier, as each season of the year approaches, the energy plans turn to the specific operational forecasts. The trader has many options to choose from including forward monthly strips from regional providers or possibly through NYMEX. But, it is still not exactly clear just what the peak loads could be, or how low the average or minimum loads could be. Forecasts are often inaccurate, and buying forward (either from the supply or demand side) can prove extremely costly.

The California electricity market during the summer of 2001 is an excellent example of this difficulty where the planners expected a hotter than normal weather pattern that never emerged, and customers responded to pleas and fears over the forecasted repeated blackouts through passionate conservation. The result was that the Department of Water Resources bought forward more electricity than they needed and found themselves selling the excess back into the market at a significant loss.

Similarly, at least one energy company bought forward trades for customer demand reductions from large industrial customers—shutting them down for two years—which might prove unnecessary, or at least costly, in light of the recent market characteristics. Therefore, planning flexibility is desirable, but the customer seasonal demand-trading options must be available for a significant number of operating hours. This tends to rule out a large portion of customer voluntary load reductions because the number of annual hours of operation might exceed 1000, unless operation of the choices can be automated. Customer-owned, distributed generation might be a viable option if it can comply with regional air emission restrictions.

Several strategies are possible here for customers to implement, but the repeated daily operation of a generator will likely require smooth transfer to and from generator operation. One of the most likely possibilities is to run the generator on circuits dedicated to the refrigeration and cooling systems for the building or process. Ironically, this is the same concept as the peak-clipping strategy customers might have attempted in the past. However, now the market value is tied to a trading relationship where value is clear, rather than being driven by customers’ attempts to beat the traditional demand and energy rate schedule (which, to their anger and dismay, they seldom did). As most customers came to realize, it took only one miscalculation a month or one failure for their generator to set the monthly demand charge. Even customers with redundant generators (that is, twice the generation potential required to meet peak demands) could seldom beat the rate—Murphy's Law and common mode failures did them in.

The largest MW and MWh block of customer flexibility occurs with day-ahead and morning-of notification of savings opportunities offered to them. Prices for individual hours are often forwarded to customers for consideration in the Eastern markets either by estimating prices in each hour (common in the Northeast), or as an average price for a fixed block of hours in the afternoon (commonly offered from 2 to 6 p.m. in the Southeast). As the individual hours of need draw close and prices typically move even higher, there are other customers who prefer and can respond to short-term notice and can reduce operations or start a generator. Most of these customers want a minimum run time on this type of interruption of four hours and a maximum of about eight hours.

Evolution in Customer Demand-Trade Participation

Demand trades are successfully being used to replace supply-side alternatives, and have been used for decades in traditional bilateral (for example, curtailment) agreements. The movement to true trading style structures is more recent and simply reflects where market mechanisms are at the time. The U.S. energy industry is just now learning how to offer more choices to customers to expand participation in this partnership. However, the partnership itself is far from new.

Most of the demand-response relationships were curtailment or interruptible agreements where the customer agreed to reduce their energy use (get down by, or down to, a given electricity demand level in a given hour), or released the control of all or a portion of their operation to the energy company for direct load control. The latter ranged from water heaters, air conditioners, and pool pumps in residential homes, up to process-control options where major portions of an industrial plant were interruptible on short notice. Customers received incentives under all of these scenarios and those incentives were significant in many cases. However, the customers were not always appropriately informed about the serious requirements in these agreements and the likelihood they could be exercised for several days in a row. The situation was fine for both counterparties because the agreements were approved tariffs and the customers generally weren't being asked to respond to demand reduction requests more than occasionally, so compliance was easy.

Then, constraints and price spikes in the electrical systems in the Eastern electricity markets occurred in the summers of 1998 and 1999. This angered some customers when they saw the limited discounts they received in comparison to actual market prices. Similarly, there were continuous price spikes in the Western markets from the summer of 2000 to May of 2001 where customers were curtailed beyond agreement limits or fined for failure to curtail. Those that could curtail and had creative trading relationships with their counterparties enjoyed benefits. One Pacific Northwest utility exported 38,000 MWh in just six months into the California market from their demand trades with just a handful of customers.

What can be learned from all this? Working with customers on price responsiveness can include a range of counterparty relationships, not just the unilateral agreements typical of traditional regulatory structures. In addition, securing repeatedly useful demand-response resources from customers requires that agreements are bilateral and fair. In such an arrangement, neither side attempts to game the other to benefit unfairly from the relationship and both sides have a reasoned understanding about risks and rewards. Customers who can assume more risk or who provide greater value are rightfully entitled to more reward. Customers who create risk through poor or unreliable performance should bear the consequences of their actions.

This all requires communication and customer interest in participation. Customers need to be educated about the opportunities and recruited to participate. Also, the demand-side resource needs to be traded against the alternative supply-side options. This value chain is constrained at the moment by regulatory rules and incomplete market mechanisms. For example, a wires company might not be permitted to engage the customer in a demand trade, and the customer's potential energy suppliers might not be willing or able to do the heavy lifting required to execute that demand trade in regional markets. This customer's demand-response capability becomes a stranded asset.

In addition, in many areas of the United States at this time, there is a raging debate about who even has the responsibility for reliability of the electrical system. Is it simply good enough for energy retailers to submit balanced schedules to an ISO (or RTO if that is in place), leaving reliability to the ISO who has little to no relationship to customers? In addition, the time window of concern to ISOs is the hour ahead and intrahour power requirements and, as a result, ISOs might tend to force customer demand response into these short time response models. Plus, ISOs are rightfully concerned about actual performance each second, and are thereby prone to insist on near real-time metered results from customers to be considered in their operating plan. This informational requirement and its costs will limit the size of individual customer participation, even though the aggregated benefits are significant.

Even so, where ISOs are responsible and in control of reliability, who are the best agents to decrement scheduled loads using demand trades? A truly open market would permit third-party demand-response aggregators. Such a market would also permit distributed generation developers to install, maintain, and operate their equipment for customers and bid this generation in, or be able to receive capacity payments. Progress has been made in developing such market approaches in certain areas, but much of the United States faces uncertainty and limitations at this time. Such uncertainty will be resolved over time, but the questions of who can and should work with customers to employ demand response is limiting customer participation and slowing the movement toward full implementation.

Engaging the Customer in the Trading Process

Today's customers are looking for ways to save money on their energy bills, and demand response has generated a lot of interest because customers have generally found that it can be implemented with little to no capital and is minimally disruptive.

Many customers are especially interested in voluntary agreements because they have the freedom of choice as to whether to participate on any given day or not. That same utility in the Pacific Northwest found they could acquire over 100 MW of new demand response from their large customers who would not agree to curtailment mechanisms (where they would have had to respond), but did agree to voluntary agreements. Several of these customers responded over

40 times in a six-month period to the opportunity to save money. Curtailment agreements usually have much lower limits to the number of times they can be called into effect.

Based on experiences so far, it is safe to say that energy companies that offer, and seriously market, a creative and balanced portfolio of demand-response choices will find substantial numbers of customers who express interest, sign up, and reliably participate. However, preventing customer interest attrition requires careful attention to certain details, otherwise the demand-response capability might be lost. The demand-trading relationships with customers can be degraded by:

1. Too many choices being offered to customers. Typically, any more than three or four choices in demand-response programs tend to "confuse them and lose them" because customers become frustrated in the selection process.

2. Changing the rules for customer participation. For example, voluntary load management customers were originally asked to respond to prices, and then were asked to submit bids with prices in California in 2001.

3. Uncertain or changing incentives and economic benefits (for example, frequent high prices in one year, but not in years to follow).

4. Insistence on near-real-time metering imposed on hourly and day-ahead agreements where LSEs have already scheduled those load reductions. The costs for such enhanced data mechanisms are simply not required to execute and settle the trades, and insisting on that extra expense kills participation.

5. Treatment of the customer (for example, a "take it or leave it" disposable relationship format).

This customer interest attrition is critically important because we are moving from a model where all customers were captive and had only one energy provider, to one where customer choice might truly be available. It was never easy for even the regulated energy companies to engage customers in demand-response partnerships that were repeatedly valuable year after year. It took a sense of trust and commitment on both sides to make that work. Now, the customer relationship might be lost due to lack of interest on the part of the existing ranks of retail energy providers, or a transient economic value signal.

What too few market participants and regulatory bodies seem to realize at this time is that customers are not easily engaged in this dialogue. They might respond when frightened into participation (such as the fear of blackouts during the summer of 2001 in California). Or, you can simply threaten that if they don't reduce electricity demand by 20% their power will be cut off, as Brazil has done (rationing). However, customers tend to become "hard of hearing" and even more resistant to participation over time while, when initially embracing the concept, they begin to think either someone has "cried wolf" or that their regional energy company is simply inept at managing system reliability.

Similarly, customers might be lured into voluntary agreements when the benefits seem high in relation to prior curtailment payments, but then become disheartened and disinterested when price signals fail to emerge (as recently seen with FERC price caps in the WSCC).

Even though customer demand trades might not be as firm as supply-side agreements, they are available at an attractive price, and therefore have significant value in the portfolio of options. But, there is a delicate balance in how benefits are shared between the customer producing the demand trade and those who make this trade possible and exercise it in the market. Because the size of the voluntary demand-response resource is, at least in some broad way, proportional to the incentives customers receive, one critical element in the trading program design is the payment customers get for their demand response.

How much should be passed on to entities other than the participating customer? That is, how much of the benefit should go to nonparticipating customers served by regulated energy companies? How much is appropriate for the trading organization to retain for their efforts and risks in bringing this resource to market and clearing the transaction? How much of the benefit should go to the customer contact agents making the demand trade possible? These are key questions even for those who are operating in regions where energy choice has not yet been implemented. This means thinking through the business relationships emerging from the pieces of previously vertically-integrated companies that break up into links in the electricity value chain, to be sure staff time and expense are reflected in the benefit splits between the customer and the team of market players necessary to implement this opportunity.

Someone has to engage the customer in this dialogue and sell them on participation. This is not a small expense, and is often only one of several things customer contact people could have on their minds. Marketing and sales personnel generally want the offer to the customer packaged up neatly, including collateral and simple participation agreements. That doesn't come without a price. There is work to be done creating a bilateral context for the agreement itself. For instance, terms such as "liquidated damages" could be changed to "benefit corrections for under and over delivery of demand response." But, that isn't going to happen without extensive dialogue with the wholesale trading floor. Otherwise, the demand-response program will likely satisfy the traders but fail to attract optimal customer interest. Bilateral means both sides agree. The industry must get past the old unilateral paradigm of customer agreements: "here it is—take it or leave it."

Benefits Sharing (Who Gets to Keep the Benefit? And How Much?)

Key to this customer communication is the economic benefit to the customer for their participation. Attempting to give too much of the benefit to the customer tends to defeat the economic benefit of having customer demand response, because the net effect of the arbitrage is minimal on the energy company. Offering too little benefit to the customer obviously kills their participation. What is the right balance? Most energy companies are finding that giving about 50% of the expected benefit to the customer seems to be considered fair by the customer. How the remainder is spread between those parties who enable this resource to produce economic value is subject to many variations, depending upon the business relationships involved.

Vertically-integrated energy companies tend to pass all of the remaining benefit through a fuel clause adjustment and do not try to cross-charge their internal departments for time and effort required. This is natural for many reasons, but fails to prepare the organization for the transition to open markets where some form of benefit-sharing between market players would have to occur to pay for efforts expended and risks taken. One interesting example of how this can be apportioned comes from the rural electric cooperative (REC) world, which might be an interesting model for others to consider.

Here, the wholesale market interface is maintained by the G&T and its trading organization (often an outside organization) and the ultimate customer is served and metered by the member co-op (EMC). Splitting the benefit can be accomplished using a sliding scale where the customer receives 50% of the price avoided and the remainder is split by paying the trading organization outright for their efforts and splitting the remainder 50/50 between the G&T and the member EMC. The sliding scale occurs because the trading organization usually wants a fixed fee per trade, while the trade value is split among the remaining parties. In a sense, the EMC organization is recognizing that the execution of the trade is a fixed cost, and the value of that execution is shared among those who enabled that trade. Cost-shifting fears were allayed by making sure market-based demand response was not used to shift cost allocations by simply adding back the actual measured demand response to the member system load.

Most voluntary demand-response programs operating in the United States also back out a lost revenue correction from the benefits offered. In a sense, this sounds quite fair to both parties if the customer turns off lights or operates a generator because those kWh have been lost. This charge is very significant when markets are capped at such low values as they are in the WSCC at the moment, and are potentially contentious in the customer service relationships over time in all situations. Remember that many process companies will simply consume more kWh outside of the hours of curtailment. Once customer demand response is openly traded, this issue will simply go away because value will be defined by what someone will pay for the resource and not just by what someone feels they might have lost along the way.

There is also the potential for the benefit-sharing mechanisms to depend upon a multitude of factors surrounding the customer's performance and the ability to meter actual demand response. In other words, one could justify a higher (or lower) percentage of the market benefit depending upon the measurement and settlement risk any one customer has in their demand response. For example, commercial customers have relatively smooth and consistent daily load shapes and can, with proper education and care, bid demand response quite accurately, especially if it is the result of banks of lights being turned off. Manufacturers might well be quite reproducibly accurate if they simply shut down a process line or banks of lights. Water authorities are also potentially reproducibly accurate in their demand response because they might offer reduced pumping operation. On the other hand, a steel mill might offer less surety about what was really being avoided in any given hour because of the relatively variable hour-by-hour load shape.

This predictability of the actual hour-by-hour demand response based upon pledge has real potential value, especially in the Eastern markets where the hourly price variations are significant during price spikes. On the other hand, where the prices are pretty much the same in each hour of the peak period (as trades tend to occur in the West) it might not matter at all, just as long as the pledged MWh and the actual measured MWh are within acceptable tolerances. Similarly, there might be significant value in having metered feedback about actual customer demand response so the customers can actually see their performance during the curtailment event and are not "flying blind." One could argue that customers should be willing to pay for that feedback because they are the ones who normally lose a portion or even all of their potential benefits should they fail to conform to pledged performance. Interestingly, actual practice at this time refutes such a perspective. Customers seldom are even willing to pay for the monthly communication charges associated with getting to the meter. One could summarize this with the retail imperative: customers won't do it, the market values it, so someone else should.

What Are Acceptable Demand-Trade Accuracies and Verifications?

Customer demand trades frequently are small (100 kW in each of a minimum of four hours is a typical minimum) and wholesale markets trade in a minimum of 25 MW blocks. Aggregation is clearly needed to reach such levels. How close is good enough on individual customer trades before some form of penalty is imposed? Do errors cancel with aggregation?

Recent experience indicates that energy companies begin correcting (imposing liquidated damages on) the benefits offered to customers for demand response as low as 10% below bid, and most will get rather aggressive about this when customers fail to hit 75% of bid. Most energy providers will give customers credit for all of their demand response above pledge until it is more than 125% of pledge, above which some simply ignore additional demand reduction and others start adjusting benefits down. The ability of any one customer to meet these requirements depends heavily upon the following:

- How well the customer understands their existing energy use patterns
- The degree to which customers have tested their demand-response capabilities

It really does not depend upon the ability of the customer to read their own meter or even the frequency of energy-data acquisition. This is true because of the following:

- Customers would simply not take the time to look at this data even if they had it (most customers with energy management systems do not look at them)
- Customers just want to know what they can do to reduce demand and what that is worth to them in dollars
- Customers want to be able to easily reduce demand and receive benefits

Actually looking at demand response during the event might be very important to the energy provider, but fails the test of interest on the part of customers. Sure, there are a few customers who will sit glued to a monitor and watch actual plant operations, but most will not, at least not after the first time they are sure they know what they are doing. That is why most energy companies get arguments from customers about the monthly charge for a phone line, even though that cost pales in significance to the benefits the customer can theoretically achieve.

This is not to say that metered data isn't of value to the energy company, especially if the company was in a net sell position in the market and was counting on customer demand response to release the energy company of native requirements for that purpose. However, most demand-response mechanisms are used when the energy company is avoiding a high priced purchase and the company has the responsibility of buying power for the customer anyway—even if the customer does nothing in response to offered prices. So, anything the customer actually does is for the good.

While this lack of customer interest in real-time metered data might seem counterintuitive, this is the current practice. The cost benefit value proposition would seem to be compelling, but fails to be followed in practice at this time. Part of that might be the inability for customers to use the existing offers as low cost methods to alert and alarm customers and market participants about unusual energy use patterns. Said another way, customers are looking for “smart” energy management where the system tells them what they should do before they incur costs rather than systems that merely tell them how they are incurring costs. Most existing systems simply tell the customer they have made a mistake, not how to avoid one.

Part of this might also be due to the departmental separation of meter interrogation capabilities from both the customer contact and the trading interface personnel. Customer-facing organizations often have to beg the metering department for this data, and the software they use is not easy for customer-facing organizations to use themselves to perform these tasks. The meter-reading department generally interrogates meters once a day for customers participating in demand-response programs and posts this data to a file that can then be used by customers and others to verify the prior day’s energy use. This same meter interrogation system could poll the meters more often than that and acquire 15-minute data during the event period to provide some level of monitoring if the energy company has adequate modem bank capabilities. Because customer demand response is settled on an hourly basis, 15-minute interval data provide a reasonable and certainly inexpensive level of feedback to energy companies and their customers.

ISO/RTO participants will generally insist on much finer quality meter information, most often something less than 10 seconds. This is the domain of near-real-time metering and supervisory control and data acquisition (SCADA), both of which are much more costly in comparison to modem-enabled meters. The real question is whether this enhanced information feedback is necessary to enable the customer to participate in the market. When it comes to customers bidding in grid-paralleled generation resources, there is ample reason to insist on something better than interval metered results. However, it is also only fair to question market participants why anything more than interval data is necessary for any customer offering to reduce demand for hours on end, or even when they are using a grid-isolated generator for hour-ahead (or longer notice) markets. Bidding ancillary services might require advanced metering to settle, but hourly markets are settled on hourly averages anyway.

Aggregation is an essential tool in demand trading. While individual customers might miss on the accuracy of pledged versus actual demand response, the aggregated result improves markedly. Once customers have participated in events, it is not unusual for the aggregated pledge versus actual demand-response load shape to be accurate within ±5%, if 10 or more customers are aggregated. A diversified portfolio of demand response is clearly a predictable resource.

How Do You Measure Something That Didn’t Happen?

How can you be sure about something that didn’t happen in the first place? After all, individual customer loads can vary quite a bit from one day to the next even at the same time of the day due to variations in business conditions and the weather. How accurately can you measure something the customer claims to have done when the devices curtailed are not metered? Section 5 of this toolkit delves into this area in detail, but the answer is surprisingly comforting for most customer situations.

Most commercial and industrial customers have reasonably predictable load shapes over time. Averaging the individual hours in that load shape over some representative period (most often using a two-week rolling average of non-event days in the United States) is the baseline that represents the most common method in use at this time, and it works to a degree. However, when the curtailment event is on a Friday afternoon, many energy companies will watch for previous non-event Fridays to be sure the customer does not bid in something they would have done anyway. Maintenance days pose a special challenge because customers could claim to have decided to do preventive maintenance on a day when price signals make that attractive, when they might have prescheduled that maintenance anyway. Most energy companies watch this carefully by using their field staffs to query the customer when they are signed up, and request scheduled maintenance days for the coming months. This is important information for an energy company to gather anyway because it would help the scheduling and trading desk better anticipate needs.

As in most relationships, trust is initially assumed until some reason for distrust is seen. Most energy companies use a “three strikes and you are out” rule here and warn customers the first time their actions seem suspicious. One of the most common situations where customers might try to routinely game their energy provider is where their average baseline is not a normal operating point. For example, manufacturing customers might have multiple production lines that operate on and off for periods of time. The average of their two-week hourly energy use might look repeatedly flat and predictable, but that average is a composite of operational points and does not really reflect what the customer looks like on any one day. When the customer sees a price offer and knows they will be below that average, they could bid in their actions with little adverse impact on their business operations.

The fault here isn’t with the customer who is simply taking advantage of the energy company who did not invest the time and effort in looking at the customer’s operational profile before agreeing to let them participate in their demand-response program. Therefore, the appearance of a nice, repeatedly consistent baseline should not be the sole measure of customer demand-response acceptability. Specific discussion of these challenges appears in Section 5.

The issue regarding how baselines are developed and implemented is simply one more attribute of the bilateral agreement between energy companies and their customers—whether or not the metric is getting down by some number, down to some number, or down under some historical average. Whatever works for the customer and their counterparty works. The actual procedure used in California for baseline determination and weather compensation has been included in Appendix B of this report as an example procedural description.

One of the attractive features about most RTP programs is that these baseline issues largely go away. The customer is subject to price signals for all kWh purchased above their contract baseline kW under a two-part tariff. If they want to avoid buying those kWh, they simply reduce to their baseline. If they don’t change their behavior, their bill will be the kWh above baseline at whatever the posted price was for that hour. Customers participating in a one-part (pass-through) RTP program would have no baseline issues at the outset.

3

DEMAND-TRADING AGREEMENT CONCEPTS

Do you remember the first time you ever saw a two-dollar bill? You probably wondered whether it was real or not, and might have doubted you could use it as currency. Customer demand trading is very similar to this in that the ability to implement a trade is largely dependent upon a common understanding and agreement on exactly what is being traded, who can trade, and under what conditions. The level of common understanding defines the trade's fungibility—the ability to use the traded instrument in commerce. Demand trading requires some level of standardization and specifications. Just like one bushel of corn might not be the same as another, commodity traders must standardize requirements and have a known level and assurance of quality.

This section is about those fundamentals. Section 4 is about the price-risk attributes these agreements have in relationship to each other. These two sections, when coupled to the discussions of measurement, verification, and settlement in Section 5, weave together the necessary fibers to develop a trading strategy and offer product choices to customers.

The first step is to look at the agreement concepts. Pay special attention to the price and volume risk design attributes, price-forwarding strategies, and the intent behind the design of the agreement instrument itself. The closer an instrument comes to logical standards across individual business perspectives, the more it is tradable. The more it looks like a private deal with no open architecture to markets and data information flows, the less tradable it is.

Paying for What You Get, and Nothing More

When deregulation was first being discussed in the mid-1990s there was little or no mention of price or volume risk. Reserve margins were adequate and neighboring utilities had "gentlemen's agreements" about how they would protect each other during any unusual events. Those agreements deteriorated as the wholesale market became competitive, and the fear of low forward prices killed the plans for free market construction of merchant generation in several areas of the country. The result was that reserve margins declined over time. Then price spikes emerged as the regional markets became short of capacity, and as the laws of supply and demand and their impact on pricing replaced the old production cost-based thinking.

The price spikes of 1998 in the East Central Area Reliability Council (ECAR) wholesale market resulted in some energy companies using their curtailment and interruptible agreements for price mitigation. Up until these price spikes occurred, customers generally thought of these agreements as reliability-based resources. Now the thought that the customer was being paid a small fraction of what the energy company was either avoiding or actually making on the relationship caused some strains in such relationships. Some customers wanted a piece of the action and threatened to either drop off the agreement or even sue for compensation.

The price spikes of 1999 also added new dimensions to the economics of the power marketplace. Decisions were made to willingly default in the wholesale market as an alternative to rolling blackouts for native customers. Meanwhile, others simply stopped trading at their "maximum perception of a fair price" and blacked out their system.[1]

After two back-to-back years of price risk, several eastern regional utilities invested in voluntary demand-trading mechanisms for the summer of 2000. However, that summer and the summer of 2001 brought neither price spikes, nor even economic justification for triggering a demand-response event in the eastern regions of the United States. By contrast in California, during the first three months of 2001, interruptible customers were requested to curtail so often that they exceeded their total annual obligation by March. A multitude of demand-response programs were introduced in California by May of 2001, only to see a summer that experienced just one curtailment request on July 3.

Was it cost effective to pay customers in advance for being willing to curtail? Would customers who were waiting for high prices to participate in voluntary demand-trading programs stay in the program with no benefits paid?

There is a real question in all this about how to best forge long-term reliable and realistically priced demand-trading partnerships with customers. Reserving their demand response using the equivalent of a capacity payment is fine if the customer truly can demonstrate and deliver on that promise and is not gaming the energy company. High penalties for nonperformance, however, can greatly discourage participation, and payments must be structured to be in sync with actual customer requirements (meaning that some "pay for performance" should be included as events occur.)

For example, a program could be structured to pay a portion of the incentive as a capacity value and a portion as an exercise price that is proportional in some way to the price in the market at which the agreement is executed (called the strike price). The following example in Table 3-1 shows values from one program worthy of consideration. In this example, the customer who is willing to be called upon at a lower strike price receives a higher annual benefit than one who wants only infrequent and limited interruptions. While customers do not commonly understand the terms used, the structure of the trades, requirements, and economic benefits for them are quite clear.

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[1] To review the reliability consequences of the Summer of 1999, refer to the following U.S. Department of Energy publication: *Interim Report of the U.S. Department of Energy 's Power Outage Study Team, Findings From the Summer of 1999*, available at http://tis.eh.doe.gov/post/report.html.

Table 3-1
Illustrative Value Tradeoffs from the Customer Perspective

Option A (June through Sept)		**Maximum of 12 Calls**	
Premium ($/kW - Summer)	**$28.00**	**$24.50**	**$15.00**
Call Option Strike Price	**$0.15**	**$0.50**	**$1.00**
Hours of Reduction per Call	**8**	**8**	**8**
Energy Credit per Call per MW	**$1,200**	**$4,000**	**$8,000**
-- Total Likely $ Benefits --			
Very hot summer -- $/MW	$42,400	$48,500	$39,000
Normal summer -- $/MW	$37,600	$36,500	$23,000
Cool summer -- $/MW	$30,400	$24,500	$15,000
Option B (July & Aug Only)		**Maximum of 8 Calls**	
Premium ($/kW - Summer)	**$21.00**	**$18.50**	**$12.00**
Call Option Strike Price	**$0.15**	**$0.50**	**$1.00**
Hours of Reduction per Call	**4**	**4**	**4**
Energy Credit per Call per MW	**$600**	**$2,000**	**$4,000**
-- Total Likely $ Benefits --			
Very hot summer -- $/MW	$25,800	$28,500	$24,000
Normal summer -- $/MW	$24,600	$24,500	$16,000
Cool summer -- $/MW	$22,200	$18,500	$12,000

As Table 3-1 illustrates, the customer willing to perform for 12 calls and a strike price of $0.15 per kWh would receive a credit on their bill of $28.00 per kW of curtailment capability (or the proven capability of their generator). In addition, the customer would receive $1.20 per kW ($1200 per MW) for the eight-hour performance required per call. That same customer could have reduced the likely number of calls by agreeing to the $1.00 per kWh strike price. Alternatively, the customer could strike a four-hour call agreement (Option B). The customer is certainly being given great latitude in choice, but notice how the variability of the total likely benefits depends on how hot the summer is.

These results are not presented as a recommendation of fair value, but rather as an illustration of how traditional trading agreement designs can be presented to customers. There is always the question about whether customers will perform, but those risks can be minimized by diligence in the marketing and customer enrollment process along with appropriate adjustments for customer nonperformance. Unlike supply-side options, this relationship to the customer is marketing and sales intensive. If the customer becomes disenchanted, there is a high likelihood the resource cannot be easily reacquired. This is in stark contrast to supply-side options, which are simply a phone call or an Internet page away, albeit at a price you might not wish to pay.

Therefore, there is a question of how value is established for reservation and execution of these agreements. Customers want to know these values with confidence year after year. This way they can choose appropriate investments (such as a standby generator), because some of them might use this to partially justify their installation of that standby generator. Given that many regional wholesale energy markets do not have capacity credits, the primary indicator of the value can be assessed through the displaced agreements into which the energy company would have entered with their wholesale counterparties.

For example, if an energy company could displace agreements more expensive than the ones being offered to customers, there is little question about the cost-effectiveness of these agreements with customers. However, if the regional power market turns soft (due to a surplus of generation or a failure for the weather to produce high loads), those customer agreements might seem overpriced. The energy company would have to decide if it would be better to keep the agreements in affect rather than face the future risk and cost of reacquiring the customer participation when the power market tightens.

Another approach would be to sign the customers up for multiple-year agreements. However, customers are generally reluctant to sign such agreements because of future uncertainties in the price and mechanics of the electricity market. If the customer would agree to one, the energy retailer could look at longer-term prices to strike the deal and probably justify the installation of a generator. The customer otherwise looks at the variability (and uncertainty) in year-by-year benefits and fails to install one.

This lost opportunity can be captured if someone can justify the longer-term relationship needed in order for the customer to sign the agreement. One possibility is to tie the term of the agreement to the installation of an on-site generator that will, in part, be paid for by the energy retailer, and where the operation of that generator is tied to a call option. Because there is a physical asset owned by the energy company, the logic of the long-term agreement aligns with the asset and the intended relationships. The customer intrinsically realizes that the company installing the generator needs to be assured of cost recovery. In addition, the customer will certainly be willing to pay something for the improved power outage protection offered by the standby generator for storms and emergencies. Finally, paralleling the generator to the electricity grid might be attractive to the customer (for the interruption-free transfers to and from generator operation), and the energy retailer could properly operate and maintain this equipment (something most customers cannot do easily) for a fee.

Risk Identification and Valuation

The real question to be answered is the risk of customer participation and nonparticipation as a counterparty to the energy industry. Paying the customer for their contribution to risk reduction is appropriate only up to the value of that reduction. That sounds simple but has proven to be elusive, partly due to the newness of risk identification and valuation to the electricity industry. After all, who would have believed wholesale prices could hit $9500 per MWh in 1999? Underestimating these risks has taken several excellent companies out of the wholesale trading business and exposed several other companies to potential/actual bankruptcy.

Today's energy-trading companies have risk desks that do nothing else but watch the positions held and attempt to limit the risks taken by their organizations. Demand response has not historically been valued against supply-side risks, in part because the data has not been accumulated and in part because experience with the resource is limited. Consequently, the risk assessment tends to be made intuitively and subjectively rather than quantitatively.

For example, it is common to hear energy companies say they will make price offers for voluntary demand trades only when their company is in a net short position on peak (where they would offset the need to buy in the wholesale market to serve native load) and would have to otherwise buy at a higher price, just as long as the amount of customer demand response achieved does not flip them into a net long position (where they would look to resell offset power purchases in the open market). In a net long position they would have purchased more demand response than they needed during a time when they might not have executed a sell agreement for the excess.

The risk profile of this net short position with voluntary demand trading is clearly always to the good. If the customers fail to perform in this trading agreement (in fact, if none of their customers even paid attention to the price signals) the energy company would have had to buy the energy in the wholesale market anyway. The cost exposure is to spend the same amount of money if customers do nothing and to spend less if customers do anything to help. If, on the other hand, the energy company makes an offer to customers for voluntary demand response and executes a sell agreement counting on that resource being available, the energy company is taking a financial risk. The energy company might cover that non-performance risk with liquidated damages clauses on each of the individual customers. Also, as Section 5 discusses, customers most often have compensating errors when they are aggregated, so the aggregated risk is much lower than the sum of the constituent customer risks. Accordingly, it is very likely that imposing liquidated damages on individual customers more than compensates for the total aggregate risk the company is taking on the sell agreement.

An actual procedural document used by an energy retailer for voluntary demand response has been included in Appendix A of this report as an example.

How Should Price Signals Be Forwarded?

Should traders take the day-ahead 16-hour price signal and use that, or is it better to simply offer a higher price in the ~4-hour "super peak" blocks? Similarly, is it better to offer day-ahead prices where final estimation of prices in these hours is potentially erroneous, or wait for better estimates of prices and trade in the day-of market with the reduced number of customers who are willing to be involved in that market? Furthermore, might it be even better to only permit hour- and two-hour-ahead customer participants because there is price uncertainty until that point?

Obviously there is no one answer to this that will satisfy all market situations, but there is a logical way to evaluate the situation to derive your own answer. The best approach is the one that maximizes the total net impact consistent with risk exposure. For example, where day-ahead price risk is unsettling, one can use the day-ahead price as a warning signal and leave the final notification until day of, recognizing that some customer participation will be lost. The best way to determine whether that loss is reasonable is to look at the difference between the likely customer MW participating day-ahead versus day-of and multiply by the price errors expected. If the higher MW is dwarfed by the pricing errors, the day-ahead auction is probably not cost-effective.

Then again, if the energy company passes all benefits on through the fuel clause adjustment anyway, and it was clear that the price errors were simply a reflection of market characteristics or the uncertainty of price forecasts, then the added MW demand reduction was likely worthwhile for several reasons:

- It decremented down the daily load shape and thereby reduced the likelihood of high prices in the balancing markets
- The net effect is still likely positive because only a portion of the future price was given to the customer (that is, you would have had to be more than 50% off in the price forecast)
- The money went to the most worthy of counterparties-the customer

Once again, is offering prices in the four-hour window better than a lower price for the entire 16 hours of the on-peak period? That depends upon the resource pool out of which the energy company plans to acquire demand-trading participation. When the customer load shape and the price profile peak sharply (and, coincidentally, in that four-hour window) and the customer can decrease that peak, paying more for those hours might be clearly logical, just as those selling only in that four-hour period (having foregone trades for longer periods that included the hours preceding and following that four-hour period) can ascribe more value to their MWh. After all, the choice by energy companies to only provide energy in that four-hour period at a higher price had foregone the opportunity to sell MWh before and after the four-hour period that would help amortize their annual operating costs. In the winter months, the same logic can be used to offer two four-hour price signals: one in the morning and one in the evening.

Offering one price for all 16 hours to reflect wholesale day-ahead block prices seems intrinsically logical to many traders, but does not appear at all the same to customers. It is easier for many customers to reduce load for four hours twice a day (separated by an 8-hour period) than to reduce for eight or twelve consecutive hours. And, where the desired effect is a total of 8 out of the 16 hours, it is generally better to offer this at the times it is needed and at a price reflecting its value.

Should the Trader Mirror Prices or Optimize Demand Response Itself?

The demand trading in the Southeastern Electric Reliability Council (SERC) markets has strong hourly price characteristics. As seen in Figure 3-1 showing SERC peak prices in 1998 and 1999, the actual hourly price can be quite high and variable. Should the trading organization try to mimic this curve on the demand side, or simply estimate a realistic price proxy? The temptation is to attempt to predict individual hourly prices.

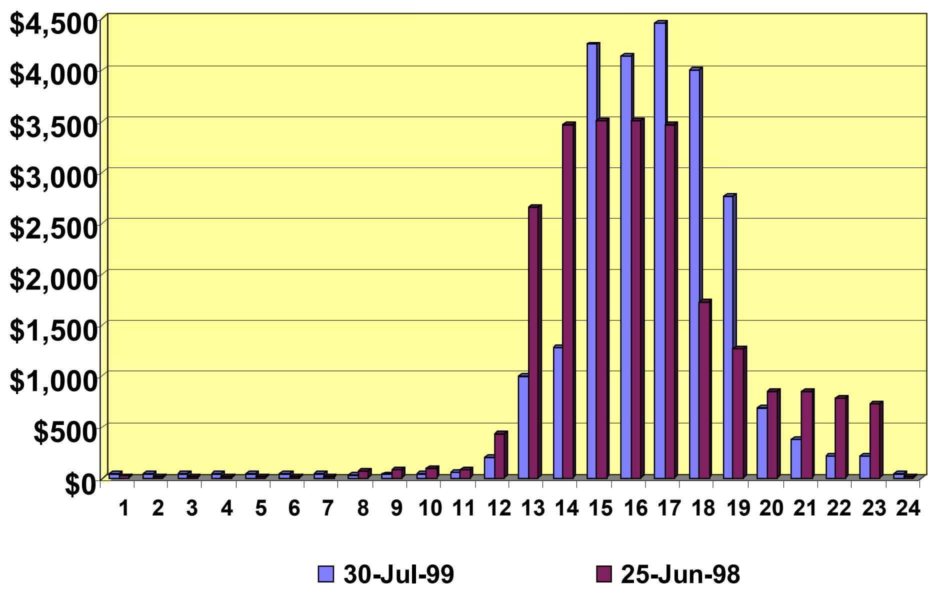

Figure 3-1
SERC Spot Market Prices per MWh

A study[2] of about 1000 demand-response transactions suggests another strategy based upon the elasticity of customer demand response plus the inertial effects of customer decisions. First, consider the elasticity effects. For any group of customers, the amount of demand response is not linearly proportional to the price offered. There is a minimum price that gets the attention of customers (that seems to be something close to what they are paying now for power), and more customers offer more demand response as price offers rise. But, there are several inflexion points in the elasticity curve where certain price ranges get more customer response than others. Then, once customers have responded to a price signal, the price offer to keep the demand response at this level can be reduced. Said very simply, once the customer has made the decision to turn something off, they don't need to be paid as much to keep it off. We think of this as an inertial effect (bodies at rest tend to stay at rest; bodies in motion tend to stay in motion). These two price signals and how customers respond to them is summarized by the following graphic representation.

[2] By Apogee Interactive, Inc. 2001

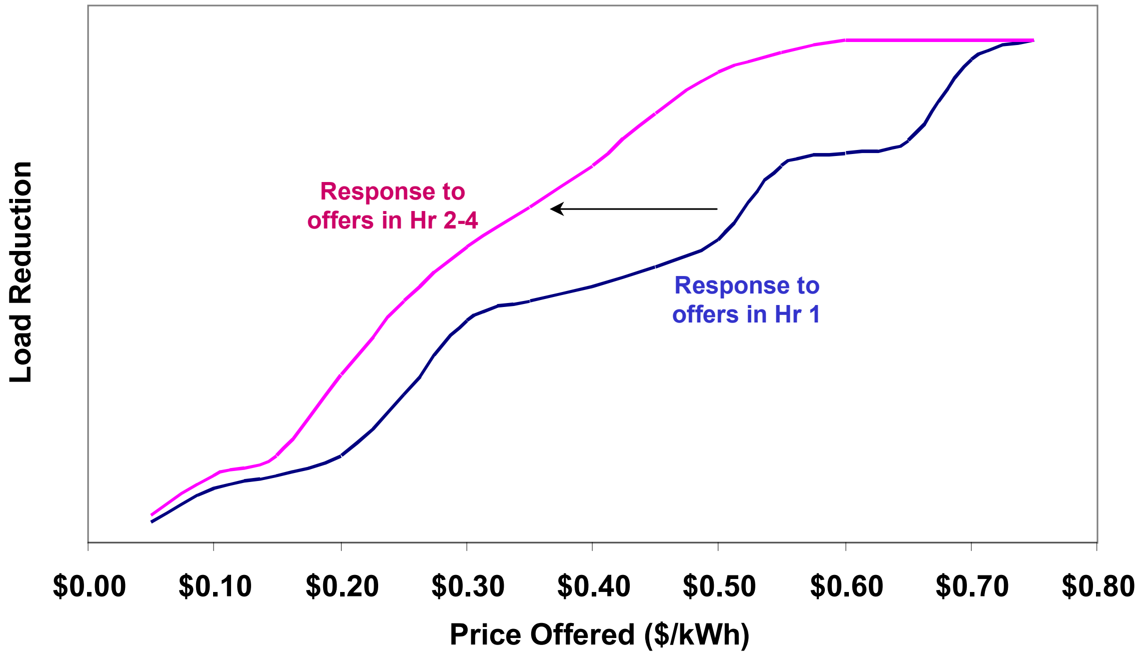

Figure 3-2
Demand-Response Elasticity and Inertia

There are two curves shown in Figure 3-2. The curve labeled "Response to offers in Hr 1" shows how customer load reductions change for this one group of midsize commercial and industrial customers as a function of price when those prices are offered in the first hour of a four-hour offer. This type of curve is referred to as customer demand-response elasticity. The second curve (Response to offers in Hr 2-4) shows that a lower price will maintain the same response in the hours following the first hour when the first hour was at the higher price. In other words, if the price is offered in Hour 1, how much lower can you offer a price and keep the same load reduction? We call this demand-response inertia, and we will come back to that, but first let's discuss the elasticity of the customer in Hour 1.

This group of customers started responding at around $0.05 per kWh and seemed to plateau after about $0.10 per kWh until the price gets above $0.20 per kWh. Notice that there is then a very significant inflexion at around the $0.20 per kWh price point, followed by another plateau just above $0.30 per kWh. These inflexions and plateaus reflect the choices these customers are making in demand response. Where a generator is being operated, the prices above $0.20 per kWh quickly capture all this resource. Therefore, prices higher than $0.30 do not increase the distributed generation (DG) operation (the customers are not increasing the generation level—the generator is on or off) nor do these prices bring more DG online (all of the customer's DG resources are now in the market, if the customer is going to respond with DG at all at any price).

The next upswing in participation in this customer group in one demand-response program occurs at about $0.50 per kWh and levels off at $0.55 or so, and the final significant upswing occurs at $0.65 to $0.70 per kWh. Experience indicates that from that price point on, the customer decisions most often depend more upon how well they are prepared to reduce demand than on the price offered. For example, some customers repeatedly ignore $2.00 per kWh and higher price offers because they had no price at which reducing production was acceptable. It had nothing to do with their production economics. It was entirely due to their inability to risk disruptions in their customer supply chain due to their inability to deliver product.

This speaks volumes about the value of working with customers to create this capability, and, interestingly, that relationship has been recognized by a handful of electricity retailers who are partnering with customers to create it. This also highlights the potential to work with customers to develop this resource. EPRI has recognized this characteristic and characterized the value proposition of working with customers in Figure 3-3.

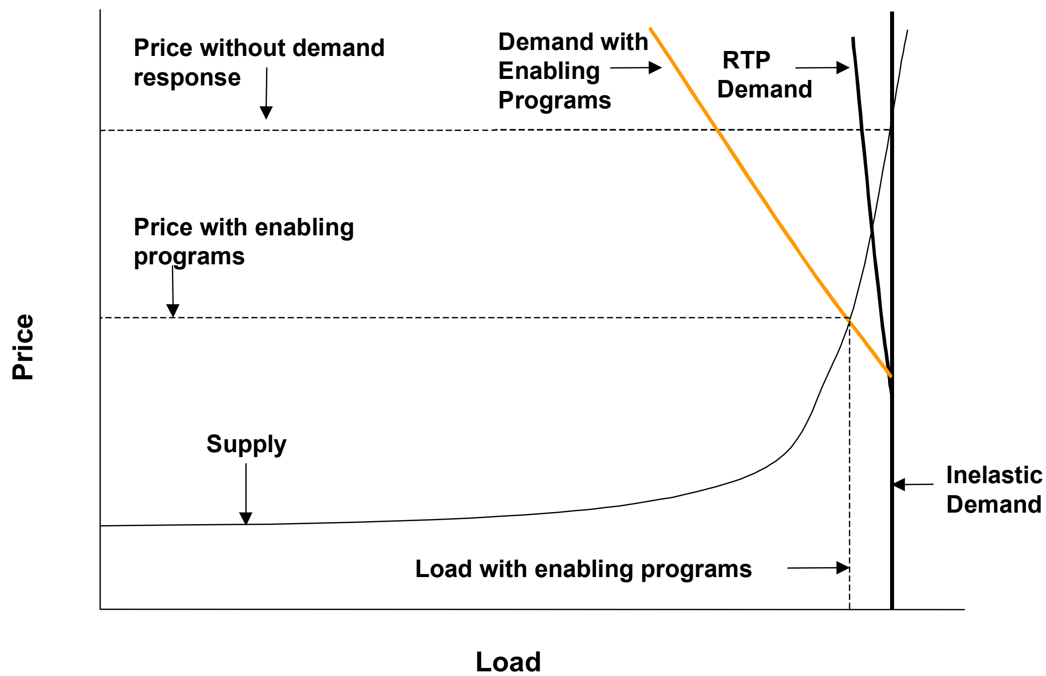

Figure 3-3
Effects of Enabling Programs on Wholesale Market Prices

While the elasticity is shown as a linear response to price, it is clear that the intersection of any elasticity characteristic at all can significantly lower final settled prices in constrained markets. Technology adoption and information efforts with customers increase that elasticity to some level, and the benefit of doing so is clear. Perhaps the more compelling comparison would be if we could show an illustration on a before and after basis, because the inflexions will likely move to lower prices and the inertial effects will probably increase due to these efforts.

The inertial effects of customer demand response are not yet factored into the thinking of price forwarding, but they should be to some extent, especially where traders want to shape a four-hour block and encourage the largest response in that block. Rather than offer one price for each hour of the block and force customers to take it or leave it, offering a higher price in the first hour and knowing the inertial effects of customer demand-response capabilities, the trader will get customers to become more active. In a sense, the trader is sending a price signal to appeal to the emotional demand-response decision process the customers use. This arises from the fact that once the customer has taken whatever action they have in response to price, the price needed to maintain that action is lower. The decision to turn whatever was off back on will only happen after:

1. The time flexibility the customer had is gone (at which point the customer becomes increasingly inelastic), or

2. The price drops to the point that the decision to turn the devices back on seems worth the trouble

Clearly, this is not the way supply-side generation resources behave. This is not to suggest that traders game this customer demand-response characteristic using this thought process, but rather consider posting prices to customers recognizing this is true. Therefore, if the trader intends to post hourly prices for each of 4 to 6 hours on any given summer afternoon, it might be better to post the highest prices in the first two hours of that hourly block, and then adjust the prices down an appropriate amount for the latter 2 to 4 hours. Thus, the composite risks of being wrong about prices in any one hour might be mitigated in part by triggering the “on time” more clearly in the customer’s mind about participation, and then offering something a bit less to keep the resource there during the desired time period. The total demand response is likely to be higher (more MW and MWh) than attempting to pick the exact two hours of highest price. Remember, the customer might receive about 50% of the displaced price, so it is unlikely that this trading strategy would expose the energy company to a loss.

Price-Forecasting Risks

The wholesale electricity markets are far from static across the United States at this time. California and the entire WSCC is still in transition with FERC-mandated price caps so low (for example, numbers hovering around $100 per MWh at the time of this report) they provide little incentive for demand response. The wholesale markets in the South and Southeast (ERCOT, Southwest Power Pool (SPP), SERC) and Midwest (Mid-America Interconnected Network (MAIN), ECAR) have virtually no day-ahead price transparency outside of wholesale traded interactions (that are largely 16-hour blocks). Therefore, perhaps the clearest early signs of what is coming can be seen in the Pennsylvania-New Jersey-Maryland ISO and reliability region (PJM) market, which has the longest standing transparent day-ahead hourly price signals.

Even so, PJM’s day-ahead price signals correlate poorly with actual day-of hourly zonal market prices. The pattern in the summer price peak periods of 2001 was toward under-forecasting those price signals. Therefore, traders and customers looking at price forecasts from a day-ahead perspective might easily dismiss the potential for participation, only to later find the actual hourly prices of serious interest. For example, day-ahead peak hourly prices were sometimes forecasted at $150-200/MWh for mid-afternoon, while actual hourly prices exceeded $600/MWh.[3]

One regional investor-owned utility operated its demand-response programs in PJM for the summers of 1999-2001 and gained considerable experience in managing this price uncertainty. This experience indicated that even though there were a few times when the day-ahead prices were higher than forecasts, they found the 50% share offered to the customers protected them from overpaying. The reverse has been more often the case in which the day-ahead prices were too low to be of interest to customers and the day-of prices were high—the low forecast resulted in a missed opportunity. Theoretically, no trading organization would want to under-forecast prices because the costs of balancing the schedule in the real-time markets tends to be punitive. However, there are situations where trading organizations that think pricing is in error can take advantage of the situation.

For example, one might deliberately over-schedule (submit a schedule where you might have more resource than need) if you believe you can acquire those resources below market at the time of need, because the balancing market will later credit you with high prices. Or, if you believe day-ahead prices are higher than hour-ahead prices will be, you could under-schedule (submit a schedule with what you believe will avoid having to pay for resources at prices you feel will be too high). Therefore, a speculator might take the following positions: Where the day-ahead price is believed to be low, the hourly load plan will be over-scheduled. If it is believed to be high, the advantage will be to under-schedule the load. But, this is speculation—not hedging. Being wrong can be costly. Interestingly, the FERC has just suggested permitting arbitrage mechanisms to reduce this inefficiency. One can almost certainly suggest that day-ahead prices will correlate better with day-of prices as markets mature. Otherwise, market participants will leave too much money on the table.

Ancillary Services Price Risk

The North American Electric Reliability Council (NERC) recognized that electric reliability can not rely on this scheduling process alone, and can only be maintained when regional energy companies also arrange generation resources to control voltage, frequency, and enough reserve to be ready to replace generators that fail to operate reliably. There are several constituents to this resource that are priced individually, but they are grouped together in the term “ancillary services.” Suffice it to say that the regional energy companies or the ISO will arrange for them under separate agreements that might be bilateral (usually for a monthly and longer term), or actually have generation resources bid prices into an auction for each of the ancillary services. These ancillary services markets are rather new in most areas of the United States at this time, and where they exist they can be much more volatile in price than the hourly markets. They might also be uncapped or capped at higher prices in markets where the hourly price for conventional power auctions are capped.

[3] An excellent discussion of the risks of demand-response price signals is available from Dr. Eric Hirst from his web site www.ehirst.com. It is titled: *Interactions of Wind Farms with Bulk-Power Operations and Markets*, Project for Sustainable FERC Energy Policy, Alexandria, VA, September 2001.

However, even with all this possibility for price risk, the allocation of costs incurred in the ancillary services markets are often socialized across market participants and might not therefore send clear price signals to each operating retailer that their specific customer characteristics are contributing to (or decreasing) ancillary services costs.

As a result, one opportunity that demand trading is not recognizing at this time is the future of ancillary services costs and the potential for cost-shifting using demand response. This is in part due to the history of ancillary services costs being small and native to any one energy company. However, as generation is sold off to others and regional ISO/RTO wholesale market operators look closely at cost allocations, there could be significant demand-trading impacts.

Part of this will be the increasing focus on all costs and the potential to have those costs shifted toward or away from any one business concern. Ancillary services costs reflect the hourly markets (because generators have the choice whether to enter into either hour-ahead markets or ancillary services). Hourly demand-response blocks are valuable at the same time ancillary services are valuable. But, one of the largest consumers of ancillary services are some of the same loads potentially reduced by demand response.

For example, steel mill arc furnaces manage energy purchases by carefully clipping 15-minute or 30-minute integrated average demands and, in doing so, impose significant intrahour swings (that is, they are contributing to ancillary services). Figure 3-4 illustrates the instantaneous load swings for two types of large customers.

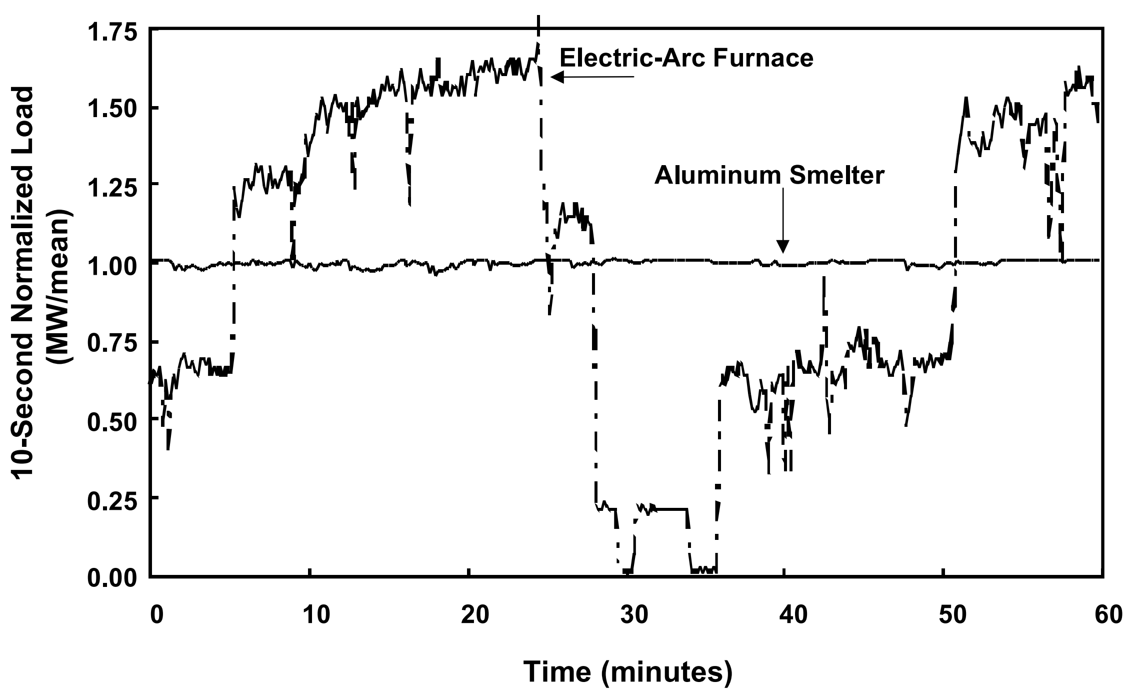

Figure 3-4
Example of Load Swings

The aluminum smelter controls demand as a flat line, and the steel mill shown here is measured on a 30-minute integrated average demand and adjusts the arc furnace to consume the same amount of energy in each 30-minute interval. The instantaneous demand can be significantly higher or lower than the measured demand from the interval meter.

Therefore, when the steel mill curtails the arc furnace load they are not only reducing prices for hourly markets, but could also be significantly lowering the ISO's need for ancillary services and the energy company's share of ancillary services costs. As a result, this customer might deserve a higher portion of the hourly price avoided. Contrast that with the aluminum smelter's load over the same hour. Both of these customers would have the same hourly average demands.

Once again, these costs are not being recognized and allocated to individual customers at this time. We expect that to change, and, when it does, consideration of these price risks and rewards will factor into price offers. However, those who endeavor to give customers like this added benefits, please be aware of an emotional factor in price offers on the part of energy companies emanating from resentment with respect to customer advantages associated with existing bundled tariffs. For example, these customers are probably currently on the best-priced tariff from the local energy company due to their size and load factors. Some energy companies resent giving this type of customer any additional benefits for demand response because they already get very low prices. One should consider, however, the following: Who gets off the airplane when they ask for volunteers and offer them $400 to do so? In general, it is the same person who got on the plane for the lowest ticket prices, because they were probably either Generation-X passengers who just viewed this as part of an adventure, or senior citizens visiting friends and relatives.

The potential for price risk assignment being discussed here is really central to the larger challenge of deregulating energy markets in the first place. Price risks were not explicitly recognized in the old regulated model and were generally shifted to retailers as energy markets first opened. Because they can prove to be large and unforeseen, retailers often fail when they emerge, and as a result shift them back to utility default providers who never factored them into their rates. The problem is that risk was not recognized early on in the process of attempting to deregulate the energy market and priced accurately. As price risks are realized and properly valued, they can be assigned and managed. Vertically integrated utilities facing retail deregulation in their service territories are still in the process of sorting out these risks, and the result will be risk-differentiated products and services. Clearly, ancillary services need to be addressed as consequent price risks or rewards in demand-response program designs. To do otherwise might prove to be a costly mistake. A creative retailer is bound to recognize these values and surprise the incumbent energy company by offering what appear to be "above market" benefits to arc furnace steel mill customers for their demand-response resource.

How Firm Is Demand Response, Anyway?

Traders really want to know precisely what they have bought and sold. Surprises can prove costly. One of the big uncertainties associated with customer demand trading has to do with the firmness of demand-response mechanisms (especially voluntary) in comparison to supply-side alternatives. Many examples have been cited about this lack of firmness. For example, it is common to hear that customers who reliably reduce demand on the first day they are called increasingly fail to deliver the promised response as the days of curtailment continue. Of course, other customers might over-deliver (produce more demand response than they indicated) on their promised demand reductions and place the energy supplier in a surplus condition. While the reliability of the demand trade might be financially firm given the liquidated damages clauses many companies employ, there is still a nuisance factor in enforcement that taints the benefits to some degree.

A key attribute of demand trades that must be carefully considered here is the aggregation of blocks of demand-response customers. Aggregation and diversity of individual customer behavior averages out the individual customer pledged-versus-actual demand-response errors and provides a firmer resource. However, obtaining the critical mass of customers needed to form the 25-MW blocks traded in most markets are not trivial, especially when the prices offered to customers are too low to draw much interest. Aggregation strategies with other regional energy companies and agents are clearly needed.

One key bridge to a future balanced consideration of demand trades in the resource stack is to stop talking about demand trading as a different resource, and to evaluate it on an equal footing with supply-side options using the same tools. In other words, stop saying it isn't worth the same and start quantifying what it is worth. Doing so requires a bit of finesse, because the analytical models used to assess the value at risk on supply-side options are not quite built to assess demand trades. Involuntary curtailment agreements might fit well into the valuation of call options if the customer must perform. However, voluntary curtailment agreements do not have a supply-side equivalent, unless it was compared to "as available" power agreements.

In general, traders and schedulers often prefer to simply dismiss demand-response resources, or might just keep them in their pocket as a last resource to give them some options and flexibility when the going gets tough. This perception is especially true for voluntary demand-response agreements that are sometimes viewed by risk desks as unreliable and of little value. However, once traders run out of regional supply-side options, or can not find anyone in the market willing to take a short block of hours or a load following agreement to get through the super-peak periods, traders do become eager for demand trades. This is true even if it simply reduces system stresses sufficiently to likely prevent further system degradation.

The Combination of Volume and Price Risk

It's bad enough finding yourself buying electric power at prices you never planned for, but even more aggravating when you have to buy even more than you planned for customers you never planned to serve. Some energy companies have seen their customers select alternative suppliers when regional wholesale markets provide headroom, only to find those same customers shifted back to them (at a standard, guaranteed price) by failing retailers when markets tighten. This compounds volume risk with price risk for the energy supplier.

Naturally, an energy company tries to assemble a portfolio of full requirements agreements, block forward agreements, and even load following agreements to hedge both volume and price risk. This is done to meet the customer requirements it expects to serve. Clearly, in some cases, energy companies do not even know how many customers they will need to serve and have almost no way to affordably hedge.

Even if an energy company can assemble the energy supply portfolio at an acceptable price and was correct in estimating native requirements, that still does not eliminate the value of demand trading. Plans are bound to be wrong and trading what you don't need for what you do is woven into the very fabric of regional energy markets. Given the proper communication mechanisms, market characteristics, and entrepreneurship, money can be made through demand trades at almost any time.

Counterparties can be found who are interested in being relieved of, or sharing in the benefits of customer demand trades with the market participants around them. Executing such agreements requires advance considerations and planning to permit price forwarding, benefit sharing, and customer aggregation. Otherwise, the only customers who would participate in this opportunity are those who have large enough trading blocks to enter into such agreements without aggregation. Chances are, these customers already have agreements in place with market participants.

These market inefficiencies are sure to be eliminated as the energy markets mature. Necessity is the mother of invention, and regional market players are investigating creative ways to bridge the intrinsic lack of incentives in current bilateral agreements. Perhaps the most creative models along these lines are likely to come from the EMCs where the cascade of necessary agreements and understanding is the deepest. Load-serving EMCs often have full requirements agreements with their serving G&T that might in turn have agreements with others to interface to wholesale markets. While the LSE EMC has the customer relationship and access to the meter, they cannot get to the market. The G&T might have an existing relationship with the EMC for demand response for native loads, but those management objectives might not align with regional market prices.

As a case in point, an EMC in the Southeast found that native peak loads were relatively unlikely to coincide with high wholesale market prices. Their demand-response signals from their serving G&T were coincident to high regional wholesale electricity prices less than 30% of the time. A key reason for this is that while it is often hot in the South, the high prices only emerge when the South and the North are both hot at the same time.

Corporate Risk Assessment

Today's large energy companies often operate as silos. Cross-organizational goals are generally difficult to implement and codes of conduct might prevent holistic thinking. This has inhibited organizations from working effectively with customers in demand trades.

Additionally, demand trading is sometimes slowed by the views that the bottom line impact is small in comparison to other corporate concerns and it does not seem to provide an adequate rate of return. Similar concerns were raised in the airline industry at the outset of what has become a standard procedure for dealing with overbooked flights. At Delta Airlines, proponents who suggested offering their customers money to get off the overbooked planes initially had trouble convincing management that this approach was sound. They encountered a corporate bias (shared by many business people) against novel ideas that initially look small and inconsequential.[4]

It was interesting to watch the first aggressive pursuit of demand trades occur in the Pacific Northwest of the United States late in 1999 where the prospect for price spikes was not even believable. The energy companies in this region pursued demand trading simply as one more tool in their load reduction toolkit, mostly out of concerns over low snow pack and subsequent low water flows. There was a reasonable fear that these hydrological conditions could have significant consequent impacts on regional generation and transmission bottlenecks, possibly resulting in blackouts. While no one knew specifically what could go wrong, there was reason to believe that increasing demand-response capabilities might be inexpensive insurance. Price spikes were not discussed.

These energy companies looked at the implementation costs of setting up demand trading as trivial in light of the customer good will and relationships these programs created, the public image enhancement, and the likelihood for some financial value to produce any return on investment. However, it was not the return on investment that prompted them. It was the thought that this added insurance would pay for itself eventually that made so much sense. What made it easy for these companies to move to selling demand-response programs to their customers was the fact that their customers had read of price spikes in the East in 1998 and 1999, and liked both the voluntary nature of the agreements as well as the opportunity to participate in benefits should they materialize.

However, the financial benefits likely to result from demand trading are often a key factor in decisions about developing this resource. The numbers are important and, at the risk desk of energy trading, they could be everything. If that group of professionals fails to see the fair value of this resource, working with customers will likely be dismissed as an unacceptable transaction. Therefore, it is important to review the evaluation and translate to the customer their demand trade opportunities using the formal language of the risk desk and compare them fairly to supply-side options. This is covered in Section 4 of this report, with this section highlighting the arguments.

The risk desk must look at both price and volume risk evaluated in light of enterprise-wide profitability risk, and not the trading-desk profitability risks alone. As in any risk mitigation strategy, an organization can attempt to insure itself against all price and volume risk and then simply go out of business because the enterprise is over-hedged and not competitive in the market. On the other hand, the enterprise has to evaluate whether its hedges are so unreliable that they are simply waiting for the turn of events that puts them out of business. Customer demand-trading approaches can be tailored to mitigate this risk, and one could argue that the lowest risk customers to serve in unregulated markets are those with market-flexible load shapes.

The risk desk should also look at the related risks that can seem small but have the potential to cause major corporate risk problems. Transmission constraints, transmission line failure, and the

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[4] Read Robert Cross's book *Revenue Management* for a frank and informative assessment of the situation at Delta Airlines.

related delivery risk can be extremely difficult to hedge. Loss of the path between the normal source of power and the load served could force an organization into securing expensive sources of power followed by blackouts anyway only moments later. Demand response can provide a substantial benefit by reducing such risks. Demand-response resources are already delivered and thereby reduce losses along with system stresses. Such system-wide stress reduction can be extremely useful in situations such as California's power crisis and the hot summer of 1999 that brought many major Eastern and Southeast IOUs within the last 50 MW of blacking out their systems.

Creating the Structured Product Offer

All this leads to the challenge of standardizing the product offers to customers to make it intuitively appealing and easy for customers to accept. Otherwise, the organization makes offers and there are no takers. In addition, the proper crafting of the structured product offer is essential to minimize liquidity risks. Remember, most customers are not energy traders, and do not want to have to understand energy trading. Therefore, there needs to be some level of intuitiveness about agreement terms and conditions for both customers and their counterparties to enter into such agreements. These structured product design terms include the following six factors.

Size of demand reduction: One must consider whether fractional MW terms are agreeable to both customers and their suppliers. Most voluntary agreements set a minimum kW participation at 100 kW of proven demand response, but customers can bid in any amount above that minimum. The assumption is that, in aggregate, the buyer of this resource can trade (or at least use) fractional MW blocks.

Hourly blocks: Most energy-trading organizations trade in large hourly blocks of 25 and 50 MW or more, and want customers to provide equal demand response in all hours within those blocks. Demand-trading programs that require this are much more difficult for customers to accept. The best programs are those where customers are allowed to bid in a minimum number of hours (typically four) and have the flexibility to vary their hourly demand reduction contributions. In addition, exposing customers to liquidated damages for non-performance limits their participation. Many energy companies use the "three strikes and you are out" rule. That is, if the customer non-performs three times in a year, the customer is dropped from the program. Customers feel that is quite fair. The more freedom offered to customers, the more demand-response capability is acquired. However each trading organization has to decide on the value of demand response and determine these optimal program characteristics.

Price-bidders or price-takers? (that is, the auction rules): Many trading organizations like the idea of customers bidding in their demand response. Even some large customers prefer that option. But all parties must see the rules of price setting on such auctions as fair. The recent demand bidding program rules in California are an example of rules that intrinsically do not work because the customer only gets what they bid, not the highest clearing bid. Nevertheless, these are the current rules for demand bidding in California. A draft of the demand bidding program implemented at San Diego Gas & Electric under public benefit funding from the California Energy Commission appears as Appendix C in this report. By contrast, traditional Dutch auctions award all successful bidders the price of the highest successful bid, and these dominate the supply-side of the business for good reason—they produce the most efficient bid stack. Demand trades should be allowed on the same basis. Doing so brings forward the most efficient stack.

In addition, the bid process should permit customers to offer multiple bid terms (that is, the customer can bid *X* kW at one price and *Y* kW at a higher price); notice that this is fundamentally different from the supply-side because the customer does not have just one option for participation. Customers can turn off discretionary items at one price, start a generator at another, and even close down their operation at still another. In fact, the most elegant model here is for the customer to enter their complete bid stack of options (essentially the customer's individual elasticity curve). The set clearing price would then actuate all customer options in the stack at or below that price.

Finally, the auction design should reflect the way customers prefer to participate in demand response. Customers generally want to participate once a day for a given number of hours, and not turn things off for four hours, turn them back on, and then turn them back off for another four hours. The latter situation imposes twice the coordination and work burden on most of them. For example, the design of the auction should not have customer bids accepted for four hours, followed by four hours where their bids are denied, and then followed by four hours where their same bids are accepted again in the same day.

However, by contrast, most demand-response systems currently consider customers as price-takers—"Tell me the price and I will tell you what I can do." This model works well for most customers, especially the smaller ones. However, the auction design should not leave any doubt about what the customer actually receives in that price signal. Any computations that might change the price should be included before the price is forwarded to the customer. Don't ask customers to do the math. Also, consider the sequence of price offers to customers as discussed earlier in this section. The demand-trade responses from customers have significant inertial characteristics.

4

THE MECHANICS OF TRADING DEMAND RESPONSE

Planning to Mitigate Volatility

Electricity is the most volatile commodity ever to be traded. Because its production cost depends largely on the underlying fuel costs (which are also highly volatile), monthly, daily, and hourly prices forecast by the best and brightest in the business can prove to be completely wrong when viewed in the rear view mirror of history. This volatility can scare a company, or an entire region (for example, California) into buying forward large blocks of power and forcing recovery of those costs in regulated tariffs. However, most areas of the United States are trying more creative ways of coping with the volatility of unregulated wholesale electric markets that operate in tandem to regulated and partially deregulated retail markets. This incomplete deregulation of electricity can cause price signals to retail customers to be completely disconnected from this wholesale volatility. The result can be potentially ruinous, and has proven to be in some cases.

Business planning and budgeting (the foundation of any corporation's success) require forecasts of both loads and prices in the energy markets, each of which are extremely difficult to prepare in open, competitive retail markets. Customers are no longer captive and can switch to the lowest price offers. The companies making these offers often don't provide incentives to these customers to reduce demands at times of high prices because communicating that opportunity was not part of signing the customer up for their service. In many cases, these energy retailers don't adequately understand their profitability risk exposure. In other cases, they don't have the needed capabilities, such as a trading organization willing to enter into these relationships or the marketing and sales staff to acquire the customer demand-trading resource.

This lack of customer demand trades in their supply options mix increases the business risks on the retailer and forces them into supply-side-only relationships. There are some markets where there appears to be adequate headroom where retailers can offer prices knowing there is a spread between acquisition and sale of the energy resources. However, what is often not seen is the dormant price risk and uncertainty in these markets. While month-ahead average prices might be known and might even appear to be attractive, locking in those prices doesn't necessarily alleviate exposure to other risks. The energy company also has to worry about delivery of that energy along transmission paths. These costs are also volatile and firm transmission rights might not even be available in some regions. These delivery risks can be "deal killers" and have trapped energy companies who have bought existing generators without due diligence about whether transmission rights from their location to the loads are even available.

There is one rule of thumb that should always be considered in planning—ask the question "what if" and avoid the temptation to base plans on statements that include the phrase "I think." Planning for what can go wrong might cost a bit more than open positions, but increases the likelihood of survival when things go wrong. That is the basis for most energy market trading. As soon as an organization implements plans based upon "I think," they will naturally speculate and increase risks. Some will certainly be lucky, but most others are exposing their organizations to ruin at some time in the future.

For example, the reason organizations do such elaborate forecasts and enter into a whole book of transactions is to produce a portfolio of supply that, through its diversity, produces an acceptable price risk for the planned future. Where costs are simply passed on through rates and customers have no choice, these risks are minimal. But, when retailers have to compete in the same market where all players are buying their power competitively, the company that does the best job on forecasting and risk management planning has the best chance for survival and profitability.

This is not about simply hedging all transactions to the point that there is absolutely no price risk. Doing so places the organization in the "insurance poor" status we would all see if we bought car insurance with no deductible. There is a delicate balance in the planning and risk management of the retail proposition that requires comprehensive analytical tools along with market insights to produce the wisest choices.

Nevertheless, there are some price-risk profiles that are better than others and do not necessarily cost more to acquire from customers. The purpose of the discussion to follow is to examine these price-risk profiles in detail for voluntary and involuntary demand trades, and encourage those who are going to plan in this area to use appropriate analytical models to evaluate their cost-effectiveness as trading concepts within the formulation of their energy-supply portfolio.

The Basics of Forward Bilateral Agreements, Futures, and Options

What bilateral agreements are and how they work is commonly known. Buyers and sellers agree on terms and conditions. Forward bilateral agreements simply set the time for execution into the future. For example, a generator might agree to sell a block of power for the months of July and August one year into the future. Both the buyer and seller know each other, are prepared to enter into this agreement, and might even be bound by this agreement to perform (meaning the agreement can not be resold or traded). As time goes on between the time the agreement was struck and when it executes, one side or the other is going to feel that the price offered was wrong because something changed. Such is life, and part of the reason energy companies do not acquire their portfolios in one afternoon of trading. The same is true in your own life if you try to pick the day upon which to buy stocks for your retirement account. You probably simply buy once a month and hope the dollar averaging works for you (and it usually does).

Futures are simply standardized agreements that have no attributes other than price to consider. They are a form of energy currency or coupons and are, therefore, able to be traded, unlike bilateral agreements, which are generally not traded. Bilateral agreements would not likely let you assign others to your accountabilities without the specific approval of the counterparty. Futures can be bought and sold many times between the time they are issued and the time they go to delivery. They act as the same type of financial hedge as a bilateral in that they take the volatility out of forward prices for the counterparties.

For example, if an energy company wants to know how much it will pay next year during a specific month for 10,000 dekatherms of natural gas, that company can simply log onto an appropriate exchange (such as NYMEX), look at the prices being quoted, and decide whether to lock that price in. They lock the price in by buying the future for that commodity for the month in question, hold it until it reaches maturity at the end of the month just prior to delivery, and sell the agreement to whomever wants to take physical delivery of that commodity. If the price had moved up, the sale would achieve a profit, and the cash flow of that profit would net out against the cost of buying the commodity in the market. For example, if a natural gas future was purchased at $3 per dekatherm and the actual price close to delivery time turned out to be $4 per dekatherm, selling the future at that time would produce an economic benefit of $1. The buyer can now use the future to go buy the gas from a local supplier at $4, but the effective price paid is $3.

Those who understand the risks with futures agreements will quickly comment that the concept relies on local markets correlating with each other in price (no zonal variances of importance) and that delivery costs can cause surprises. Anyone studying pricing in PJM would react with immediate alarm at both of these statements because both caveats have proven troublesome. On the other hand, ISO New England at the same time operated their market with no zonal pricing variations; however, that is all likely to change as these ISOs move towards one RTO. Therefore, zonal price variations and delivery risk can prove to be very troublesome assumptions.

Completing the futures illustration must include consideration of what happens if prices drop. If the price moved down to $2 per dekatherm, the sale of the future would result in a loss, but the price in the underlying local market would be lower by the same amount. Therefore, in all cases, the net price is $3. The volatility has been removed and the company can plan. Merchant generating companies can create power sale agreements with known margins simply by buying strips of fuel and selling strips of power, thereby locking in the spread (assuming the plant operates and can acquire transmission rights).

The result of all of these agreements is that the expected probability distribution of possible prices has been reduced to a known budget number. While some might argue that the real goal should be to buy the future agreement at a low price and sell it at a high price, this is a speculator's perspective, not a budgeting or hedging perspective. The reason for buying or selling the forward agreement isn't to make money on the agreement. It is to know and budget forward prices. The easy way to remember this is that the goal of a futures position is to know the future price. The futures agreement takes volatility out of forward prices. Once again, that price is almost certain to be wrong, but at least it can be budgeted.

Let's look at what this does analytically. Figure 4-1 shows the typical shape of electricity prices for a month in the future. For the record, most commodities tend to have this shape and the most common mathematical simplification of this behavior is the "log normal distribution". That is nothing more than a statement that the natural logarithm of the prices is normally distributed. The graph has a longer tail to the right of the most probable prices, and the degree to which that tail can stretch is proportional to the volatility.

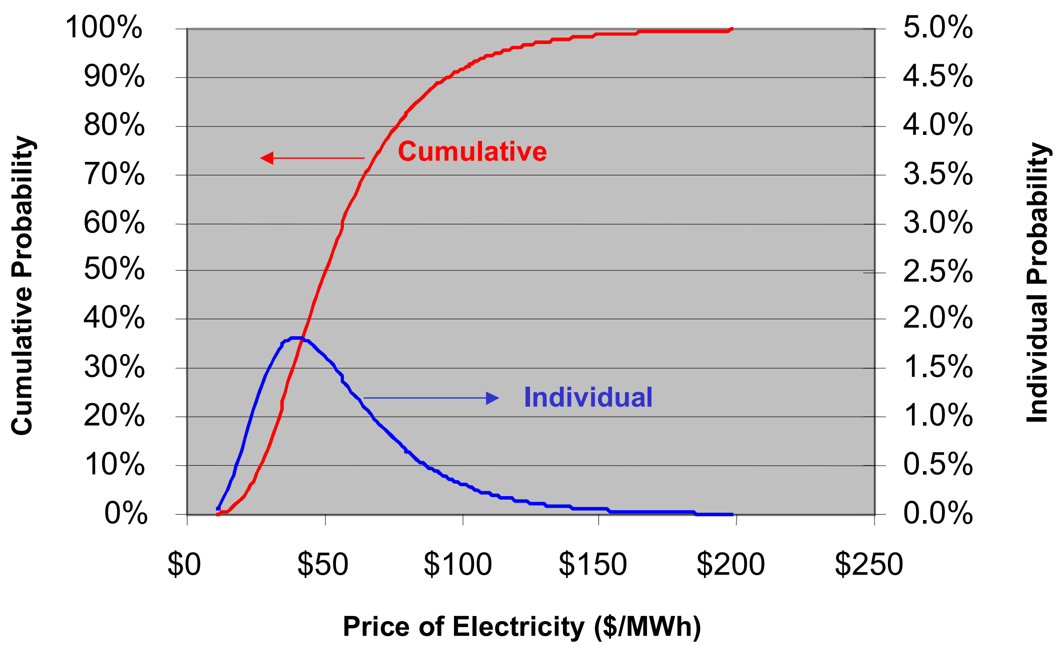


Figure 4-1
Probability of Power Prices (Price Exposure Probability)

Most risk assessments focus on the cumulative distribution rather than the underlying probability distribution. The graph of that is S-shaped and shows the likelihood that prices are going to be at or lower than a given price. For example, the graph above indicates that the price for electricity is 90% likely to be $100 per MWh or less for that month in question. Does a 10% chance of that being untrue bother you? It should! Buying the future agreement changes the price-risk distribution to a 100% chance of one price being true—the futures price (neglecting delivery). If the future for the example shown here was sold at $50 per MWh, the S shaped cumulative price curve now becomes a vertical line at $50. There is only one price to be faced—$50.

Counterparties in the markets often share (or mirror) the potential for the risks of price movements into the tails of such distributions. For example, consumers fear high prices and producers fear low prices for obvious reasons. However, producers can also fear high prices if their generator fails. Customers might enjoy low prices, but only if they can actually use that energy in the production of useful goods and services. Nevertheless, the ultimate end-use customer is a natural counterparty to the generator in the price-risk relationships.

Counterparties Like Options: Calls and Puts

Options do exactly what the name implies: they provide flexibility to "call" the future into your possession when the price of the commodity has moved above your specified limit (the strike price of the agreement), or to "put" that agreement onto someone else when the price moves below your specified strike price. There are premiums paid for these privileges, and the buyer of the agreement is purchasing the rights to exercise the option. The seller must perform if the buyer exercises the option. However, there is always the possibility that the actual spot market price will not trigger the call (or ceiling on price) or the put (or floor on price). This is described by the phrase that "the option has expired worthless." We have deliberately mixed the intuitive ways these options are used in with the description to make the terms easier to remember for those who are unfamiliar with them.

Call options cut off the high-price side of the price-distribution curve. They are essentially calculated prepayments for the likelihood that the price would be that high or higher. Put options do the same for the low-price side of the price-distribution curve. They are prepayments for the likelihood that prices would be at that price or lower. Calculating and trading the fair prices for these options is the domain of sophisticated mathematical modeling and a bit of horse-trading.

It is important to understand perspectives on these options and how they vary. For example, Figure 4-2 illustrates the likely perspective of the producer.

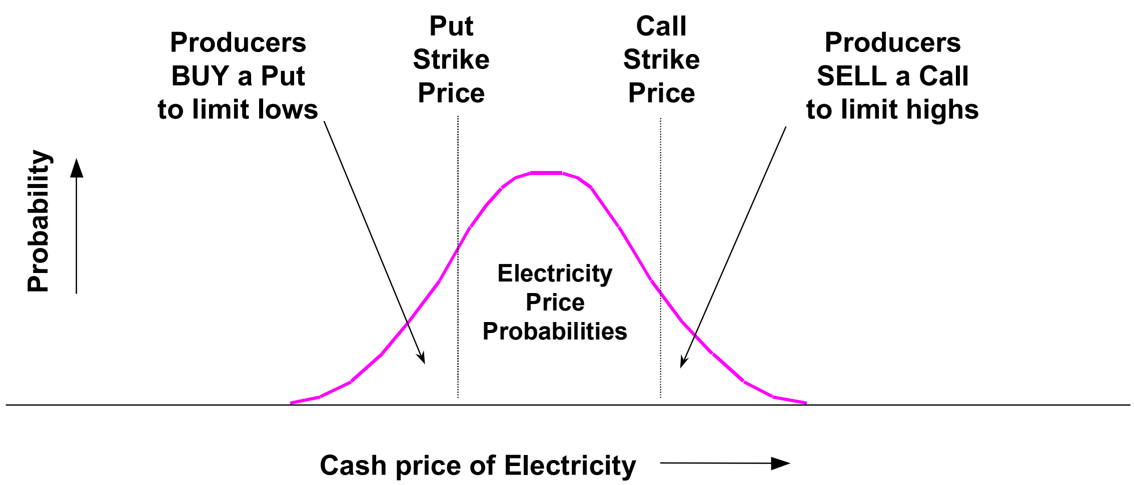


Figure 4-2
Producer Risk Perspectives

Notice that the producer can sell the call option to limit the highest price they will charge. They are being prepaid for the likelihood that the price (or higher prices) would have occurred. The natural buyer for this call is the customer, the retailer serving that customer, or the LSE. This is a natural counterparty relationship because the producer is being prepaid for the likelihood that the cash price would get that high anyway, so their expected benefits are the same (assuming that the probabilistic parameters reflect actual market conditions). Because the expected value of the call option is the prepayment, the deal is intrinsically fair and rational.

On the other side of the price-risk spectrum, as shown in Figure 4-2, the producer would be interested in buying protection against low cash prices in the market, and the customer (or their retailer) would naturally sell the producer that protection because the customer and the retailer are being prepaid for the likelihood of low prices in the market.

Shifting the discussion to end-use customers, the same type of diagram (Figure 4-3) now shows the perspective of a customer who might sell their demand-reduction capability as a call option and also sell a put on low prices. The customer is being paid to reduce demands when market prices would otherwise be too high (for the retailer) and is agreeing to be charged more for power than might otherwise be available in the spot market in exchange for a prepayment for the likelihood that this will happen.

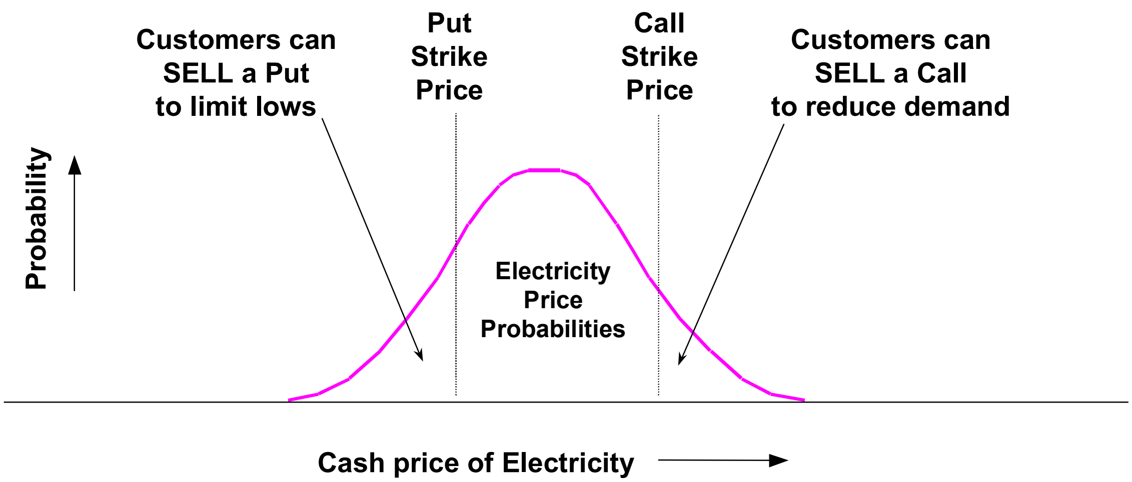


Figure 4-3
Customer Risk Perspectives

Figure 4-4 shows the example cumulative distribution function (CDF) of energy prices from before with the execution of a call option on the customer's demand response as a trade.

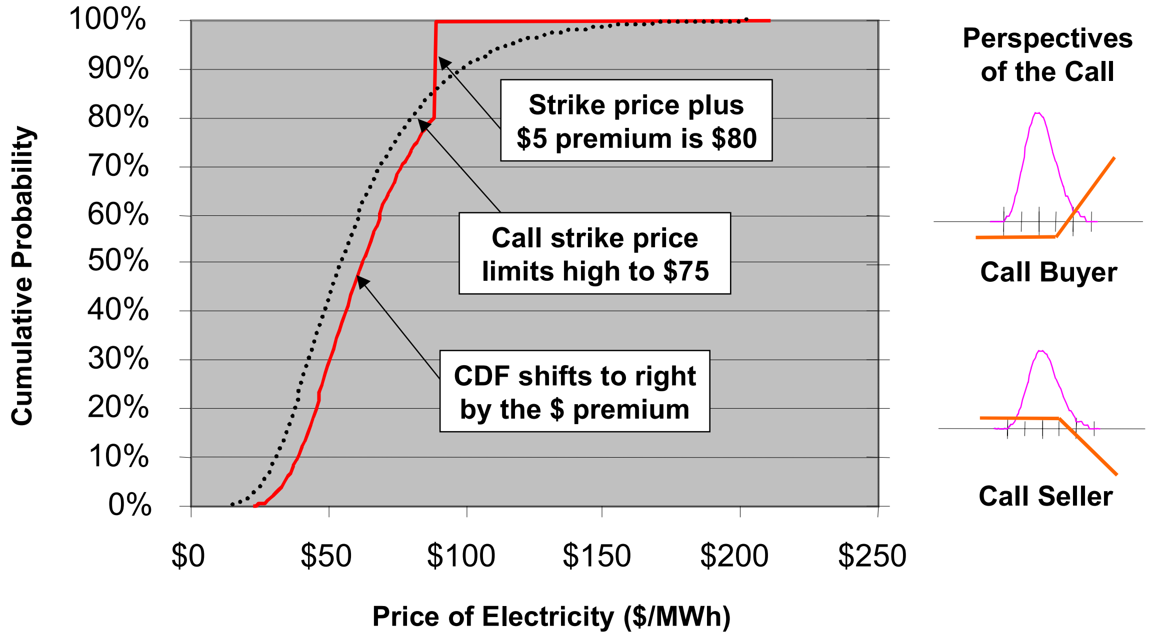


Figure 4-4
Call Option CDF

The CDF changes from an S-shaped curve to a vertical line with the use of a futures agreement (or the equivalent bilateral). The call option caps the price at the strike price and shifts the curve to the right by the amount of the premium paid for the call option itself. The perspective of the call changes depending upon if it is viewed by the buyer or the seller as shown by the cryptic diagrams to the right of the CDF in Figure 4-4. The buyer of the call is out the premium until the call exercises at or above the strike price and is "in the money" with that option when the cash market price is above the strike price plus the premium. The seller of the call has the mirror image of this perspective and is in the money until the cash price hits the same threshold. But, in all cases remember that the option was priced to reflect the value of limiting the price. The buyer prepaid for that protection and the seller was prepaid for its likelihood.

Voluntary demand-response agreements are similar to calls in that they are exercised at a threshold strike price, but most of them have proportionate benefits (50% of the incremental transaction is the most common benefit-sharing mechanism at this time). They are often called quote agreements because the energy company is quoting a value for demand reductions and asking the customer to nominate demand reductions. In addition, because they are voluntary, there are no prepayments for participation and, in fact, one could argue that customers should pay something to participate in these programs just to have some "skin in the game." These two factors (the proportional benefits and the lack of premiums) create a completely different risk profile as shown in Figure 4-5.

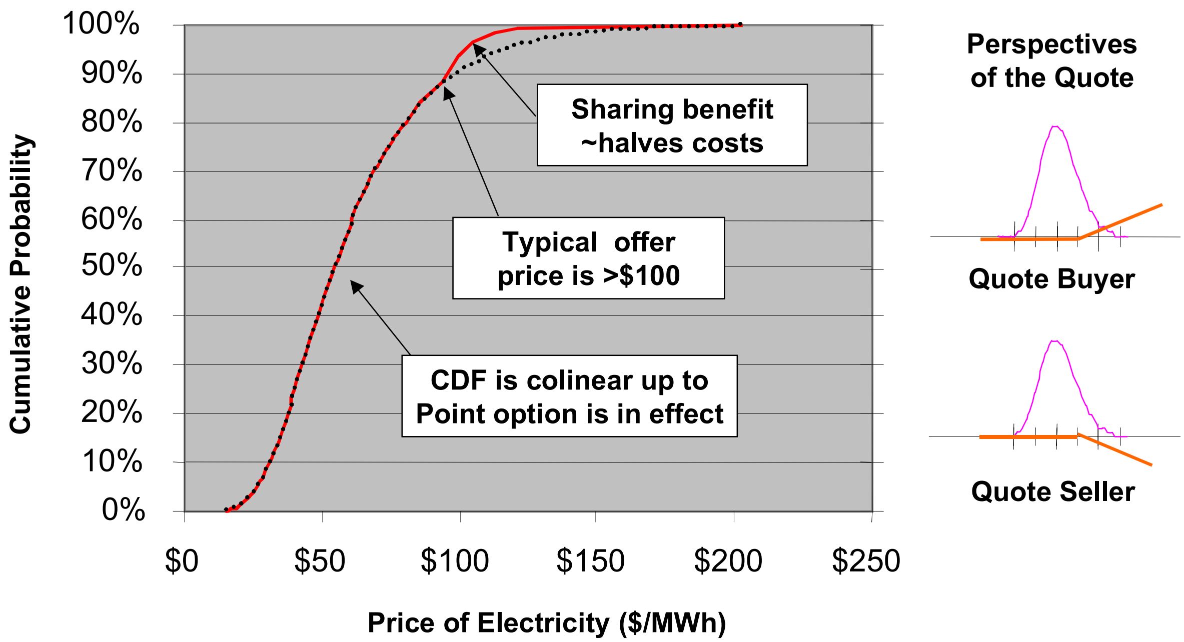


Figure 4-5
Quote Option CDF

In Figure 4-5, the price at which the offer is typically made is shifted slightly in relation to the previous example because most energy retailers will not offer customers this option until wholesale prices exceed $100 per MWh. In fact, most wait to make the offer until market prices are quite a bit higher because they just do not believe they will get much demand response. Interestingly, that might be a very bad assumption when customers are themselves in the commodity business or feeling significant competitive pressure in their own markets, and electricity is a significant portion of their bottom line. Almost one third of the 150,000 MWh of demand trades on the Demand Exchange® were at price offers of less than $100 per MWh to customers.

Once again, the perspective of the quote option changes depending upon whether the buyer views it or the seller as shown by the cryptic diagrams to the right of the CDF in Figure 4-5. In both cases, there are no financial benefits until the option is exercised, and the slope of those benefits is half of what was shown previously on the call option diagram (assuming 50% of the benefit goes to the customer).

Structuring the Options for Acceptance and Liquidity

The energy industry historically relied on its regional colleagues to provide backup services. It was cheaper to enter into bilateral agreements than to construct the required capacity for standby and backup requirements. As the industry developed, the size of the generating stations grew, making the backup of the single largest unit out of service a very significant cost. Because these were most often mutual agreements where both parties agreed to back each other up and settle up at year end for whomever experienced what costs in doing so, there was a sense of fraternity. As the competitive environment evolved, structured agreements had to replace these informal arrangements and calls were developed to reflect the individual accountabilities, as market forces began to pervade the industry.

One energy company would buy a call on the other's capacity, and the other energy company would do the same. If a third party wanted to bid on that call agreement, it could. The call had the premium to reserve the capacity and an exercise price (price paid per MWh of plant operation). The design of these calls was proven in the gas industry a decade or more previously, and they worked quite well.

By the late 1990s these calls were being traded by those without physical capacity to back them up, and using agreements without adequate financial backing. The belief at the time was that they could always purchase the energy on the open market if the calls were exercised. As any trader knows, these are uncovered calls and represent an open position with extreme price risk. The question isn't whether or not you are going to go out of business, but when. And several energy traders who did not have their call options covered with physical resources did exactly that in 1998.

Most of the call options offered today are structured on electricity futures (exchange-traded agreements with performance guarantees) underlying the market, or with the equivalent adequate financial backing. For example, call options are often quoted for the months of July and August and are commonly traded as pairs (meaning both months are purchased together) to limit the highest price in these months. These agreements are traded months in advance at round number strike prices to improve their liquidity. For example, call options might be priced at a $100, $200, and $300 per MWh strike prices. The cost of that option for any future month will be less as the strike prices increase (similar to how insurance premiums reduce as deductibles increase). The call options at higher strike prices are less expensive because they are worth less—they provide less protection from high prices and these high deductible call options are also less liquid. Finding the new buyer isn't as easy with such high deductibles. As a result, the selling trader is likely to charge a higher premium than what it is theoretically worth, because the seller is taking a risk in being stuck with that agreement if the original buyer wants to exit it.

Customer call options on demand-reduction trades are designed the same way. A premium is paid to the customer to reserve the option for a season (typically four months). However, this premium is normally paid as a discount off normal tariff demand charges all year long. These customer call options can also include a strike price at which the agreement executes, or can simply be exercised up to some number in a season (typically stated as less than 12 days and less than 120 hours a season).

Agreements missing clear strike prices for customer demand-response relationships should be evaluated carefully and might need to change because they provide no payment for the actual exercise of the agreement. The reasons for this agreement design type were that these customers were originally signed up to reflect bilateral reliability relationships and contracts at wholesale. They were ostensibly put in place for reliability considerations, and because there was a low probability that they would be executed and there was no wholesale market price transparency, the execution price was relatively unimportant. This was all well and good when customers were not called at all.

When customers were called more than once, there was no incentive payment for that execution. The customer might have chosen to operate a generator and there wasn't even a payment for the fuel they used. Plus, in some cases these customers became aware the energy companies were either avoiding high wholesale prices or were selling into those markets. This was unacceptable to astute customers and in certain cases these customers actually sued their energy providers. The correction is fairly simple in principle, but not as easy to implement in practice due to the difficulty and costs of changing existing tariffs.

The right answer is to have strike prices in the agreements that pay customers for execution. A strike price of $150 per MWh would give the customer $0.15 for all kWh reduced. This is a commonly selected strike price because it matches the customer's perception of fuel, operation and maintenance (O&M), and a nuisance factor for running their generator. The agreement at this strike price would be more likely to be exercised more than an agreement struck at $500 per MWh that, in fact, might have a reasonable probability of not being exercised at all, and the lower likelihood would be reflected in the lower reservation fee associated with the call agreement. Table 4-1 of call options and strike prices illustrates how this should be done. (Note: Table 4-1 is identical to Table 3-1 discussed in Section 3).

Table 4-1
Illustrative Value Tradeoffs from the Customer Perspective

Option A (June through Sept)		**Maximum of 12 Calls**	
Premium ($/kW - Summer)	**$28.00**	**$24.50**	**$15.00**
Call Option Strike Price	**$0.15**	**$0.50**	**$1.00**
Hours of Reduction per Call	**8**	**8**	**8**
Energy Credit per Call per MW	**$1,200**	**$4,000**	**$8,000**
-- Total Likely $ Benefits --			
Very hot summer -- $/MW	$42,400	$48,500	$39,000
Normal summer -- $/MW	$37,600	$36,500	$23,000
Cool summer -- $/MW	$30,400	$24,500	$15,000
Option B (July & Aug Only)		**Maximum of 8 Calls**	
Premium ($/kW - Summer)	**$21.00**	**$18.50**	**$12.00**
Call Option Strike Price	**$0.15**	**$0.50**	**$1.00**
Hours of Reduction per Call	**4**	**4**	**4**
Energy Credit per Call per MW	**$600**	**$2,000**	**$4,000**
-- Total Likely $ Benefits --			
Very hot summer -- $/MW	$25,800	$28,500	$24,000
Normal summer -- $/MW	$24,600	$24,500	$16,000
Cool summer -- $/MW	$22,200	$18,500	$12,000

In a sense, this discussion points to the clear need to reinvent the demand-response mechanisms into trading models, but that is not without its own set of problems right now. Many, in fact most, energy companies in the United States have regulated retail relationships, native generation, and significant long-term bilateral agreements with other regional providers to cover their native load requirements. The regulated retail customers just are not exposed to these wholesale prices because there is a regulatory barrier protecting them. Arbitraging this inefficiency against wholesale markets is underway using the mechanisms described in earlier sections of this document, but that transformation brings with it some interesting and perplexing risks of agreement migration that might be highly disruptive to the regulated relationships.

For example, customers do like known prices and discounts. Call options feel good to customers but are, by their very nature, prepayments for expectations. Actual cash values in the energy markets can make them, in retrospect, look unattractive. As a result, energy companies watched customers switch off call option agreements into voluntary “shared benefits” or “quote style agreements” after 1999 only to have nothing to share during the summers of 2000 and 2001. This migration between agreements can be disruptive in planning.

RTP Risk Profiles

Another risk-sharing alternative is to show customers the price in advance and let them decide what they want to do about it, because they are going to pay it for all the energy they use in each hour. Trying to shelter customers from this volatility just transfers the risk to the energy company and these price risks just are not worth taking in competitive retail markets. In this pass-through scenario, the energy company would appear to be simply an agent or reseller, in this case with margins derived by throughput and nothing else.

This risk profile certainly sounds better to the retailer, but exposes the retailer to other challenges, including the accuracy of price-forwarding obligations, the volume risks associated with not knowing customer responses, and the potential for lost revenues (for example, if the customer is gaming their actual load profile against bundled rate designs). The lost revenue issue is important. Where RTP appears to be a discount over traditional bundled rate designs, it is likely that the customer will sign up and completely ignore the price signals. When prices do spike in one year, the customer merely jumps off the RTP agreement on to the cheaper bundled agreement (which commonly have regulatory lags on any price increases). The customer can and will likely game the price discrepancies between RTP and bundled tariffs.

The volume risk challenge is also significant because it feeds back into the price forwarding risk. Forwarding a price is half of the story. The trader wants to know what the customer is going to do about their energy use in response to that price signal. If the trader forwards a price assuming a modest demand response and finds out too late that the customers drastically cut back on energy use, the price offer might prove incorrect.

Getting back to the first responsibility mentioned (accurate price forwarding), what is RTP and how soon can the customer find out they are buying at a given price? Most energy companies in the United States who say they are using RTP are not really doing so. They are calculating a theoretical price using the traditional native requirements/native resources balance model and the generation bid stack available to them. These calculated RTP models most often predict high prices when regional markets are low and low prices when regional markets are high because regional power prices correlate more with broad U.S. weather patterns than they do with the weather in one region. RTPs work well when they can come from an ISO or RTO and reflect actual displaced transactions for the energy retailer.

In addition, the gaming problem deserves discussion as well. Most customers who will select RTP will do so because they believe (or know) that doing so will give them a better price than the standard bundled price offer. The most common underlying justification is that their load shape is better than the one used to calculate the standard bundled offer. Therefore, the RTP would offer the retailer lower expected returns than the standard against which it is compared. While the price-risk profile is better, that has to be balanced against the margins lost by offering it. Given that RTP customers do not indicate their buying behaviors (how much more or less they are expecting to use above baseline), one could also argue they represent significant volume risk. For example, high prices might scare customers into using so much less that the price signal reverts to lower levels.

Finally, most customers who say they can and will respond to a price signal cannot respond (or at least cannot repeatedly respond) to a price signal. If wholesale prices spike frequently, or move to higher than anticipated levels, customers might quickly abandon RTP for the comfort and protection of less volatile price structures. While pulp and paper mills can automate their generation and be wonderful counterparties to RTP, even they know one mistake on a hot summer afternoon can destroy years of benefits. That is why they automate curtailment procedures for their own protection against the possibility of their own generator failure. One must consider whether customer interest in RTP can be sustained if the price-forwarding mechanism is correct by design, and there is significant volatility in the market (such as can happen where peak market prices are uncapped).

Therefore, in summary, while RTP often has high appeal to regulators and energy companies challenged by volatility, RTP can be extremely difficult to sell to most customers, and the ones that buy it easily are likely to be gaming the situation. The customers that are the most interested thereby cause revenue erosion for the energy companies in comparison to bundled rates. An additional dose of uncertainty is added because customer actions in response to price signals are not known until they happen. Therefore, be very careful in the use of this agreement type. It does, however, potentially shift price risk to customers in the best of situations where the energy retailer has the right type of customers, if those customers will accept it.

Load Shapes and the Predictability of Load Shapes: The Volume-Risk Element

Electricity trading is evolving from large, bilateral, long-term forward agreements toward diverse portfolio management including a multitude of market structures. Optionality is the buzzword, and finding flexible sources to meeting planned requirements is not easy when inadequate reserve margins exist in a region. At the same time, it is increasingly unusual for large blocks of generation to be owned by the same company serving customers. As a result, companies serving customers can have both volume and price risk. When the energy company is the last resort provider at prices set at guaranteed savings from historical prices, one might be reminded of California's problems in 2000 and 2001.

In almost every situation, volume flexibility (having access to a quantity of tradable commodity) in the energy supply portfolio is becoming increasingly important. Energy traders might have many different perspectives of these flexibilities and not all will consider the same trading flexibility structures of equal value. For example, an energy trader trying to assemble the portfolio for the annual load shape of the manufacturing customer shown in Figure 4-6 faces fairly flat monthly needs during the on-peak weekdays and little-to-no weather dependence.

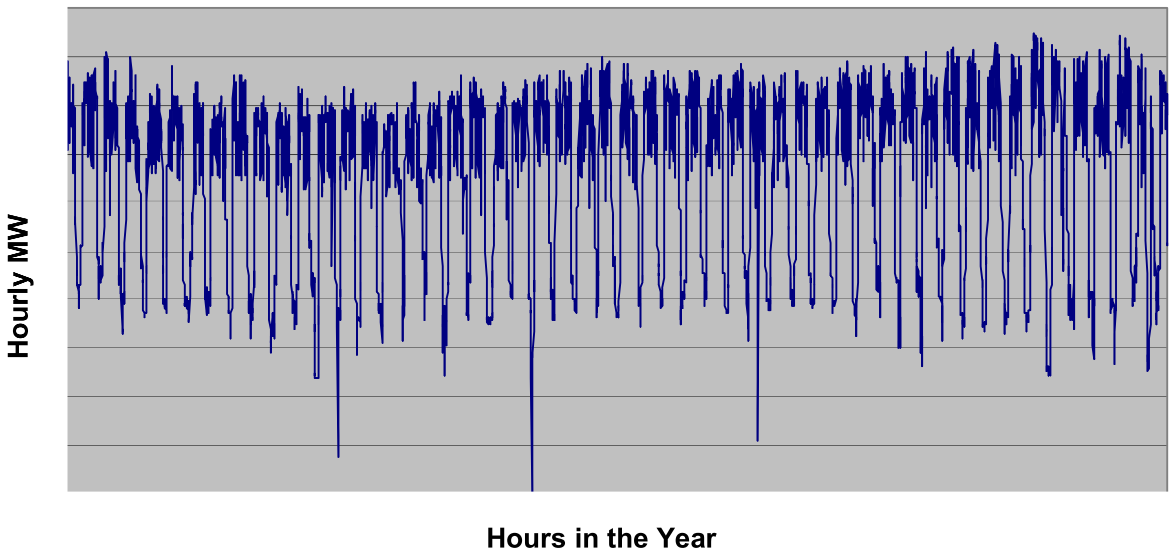


Figure 4-6
Manufacturer's Hourly Loads over Calender Year

In historical energy company rate structures, this high load factor characteristic might entitle the customer to the best pricing. However, with today's energy price volatilities, it might matter more what the customer can do on any one day in response to price than what their annual load factor looks like. Price spikes have occurred in the Spring and the Fall in some markets due to extremely low operating reserves as power plants are taken out of service for maintenance between peak seasons.

In any event, this is precisely the kind of customer that has a reasonably repetitive daily average load shape and whose baseline can be established on a two-week rolling average with a high level of confidence. Figure 4-7 is a graph of a typical four-week period with several repetitive patterns that can be confidently factored into a baseline.

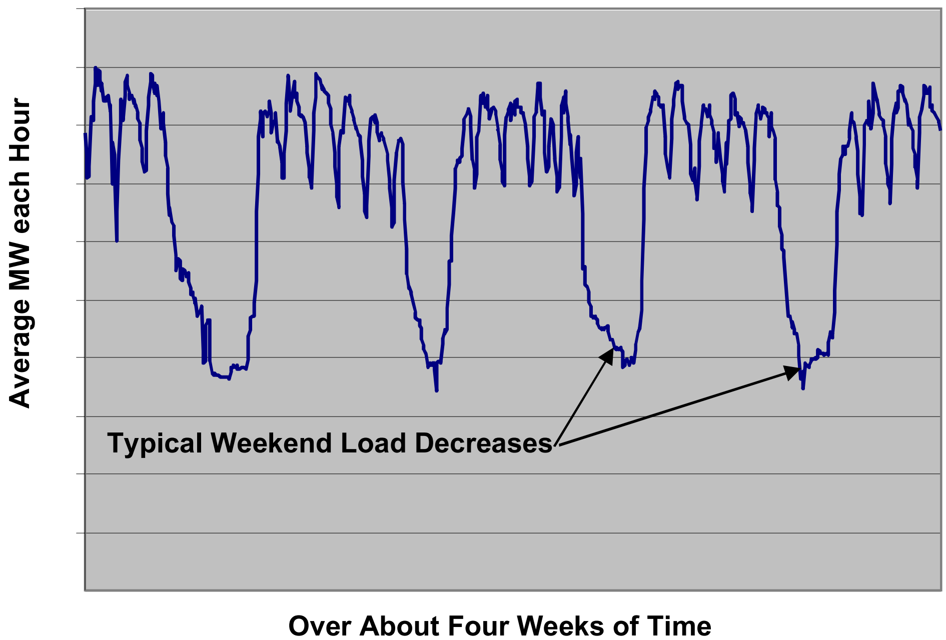


Figure 4-7
Typical Manufacturer Load Shape Each Week

Notice that the typical weekdays peak with very small day-to-day variation. Weekends drop off significantly, and the Friday afternoon drop-off shows clearly as well. Also notice that a customer who was to bid in this Friday afternoon for demand reduction could game the energy company if Friday's typical load shape was not compared to an average of historical Friday load shapes. Fortunately, most demand-trading programs recognize the possibility of pattern abuse. A typical agreement and procedures that an energy retailer can use to decide what days constitute a fair baseline, and an approach to calculating this baseline, are in Appendix B of this report.

The key question the energy company must ask before enrolling this customer in a demand-trading relationship is the size of their minimum demand response in relation to their normal energy use. Several "scoreboard attributes" have now emerged from experience that help here.

First, the customer's demand response has to be a *minimum* of the higher of either the:

- Amount that is clearly discernible when executed (that is, you can clearly see the effect of the demand response in comparison to the baseline), or
- Minimum kW and kWh amount (dollar per transaction) worth reconciling and settling

Unfortunately, simple rules are often simply wrong. The widely used rule of thumb on the first scorecard attribute is that the demand response must be a minimum of 10% of the peak load. The real question has more to do with demand-response signal-to-noise ratios than with the size of the customer. Discerning 5 MW of demand response in one 400 MW aluminum smelting customer's load is easy because their load shape is so repetitively flat. Finding 20% demand reductions for a few hours of claimed demand reduction in the electric arc furnace of steel mill operations can be more challenging. This is both art and science, and there is no substitute for understanding the customer's operations and flexibility.

One guideline that works well for this attribute is to compare the event day with the prior day and the two-week rolling average as described in Appendix B of this report. If it is clear that the customer changed behavior during the event period by reducing from normal operation and then returned to normal operation after the event, the signal-to-noise question has been resolved. If, on the other hand, there is no apparent pattern to the day-ahead and day-of load shapes in relationship to the baseline, the customer might have simply gamed the event. (Naturally, this pertains primarily to voluntary agreements. Why care whether the customer games an *involuntary* agreement on any one day? It was not "bid in" for that day as a response to price.)

The second attribute for demand response has to do entirely with the cost of working with customers compared to the benefits of their individual demand-response efforts for each event. Most energy companies set the minimum demand-response threshold at 100 to 150 kW (or at one MW in some large systems) to justify the costs of customer participation. This might be fine in theory and practice, but fails to recognize that customers might sign up and then not participate at all at any price offers. Therefore, it might be wiser to insist on some minimum annual MWh customer participation, or to ask the customer to pay something for trading privileges. These fees could be waived if the customer supplies more than a given MWh of demand response per year. In any event, a fee also causes customers to think about just how serious they are before they sign up for a program they originally might have had little intent of considering seriously.

Forecasting and baseline considerations become much more complex when the weather has a significant effect on energy use, especially when the energy system is winter peaking due to electric resistance space heating. This situation is illustrated in Figure 4-8, the annual load profile and coincident ambient temperature plots from a Public Utility District (PUD) in the Pacific Northwest.

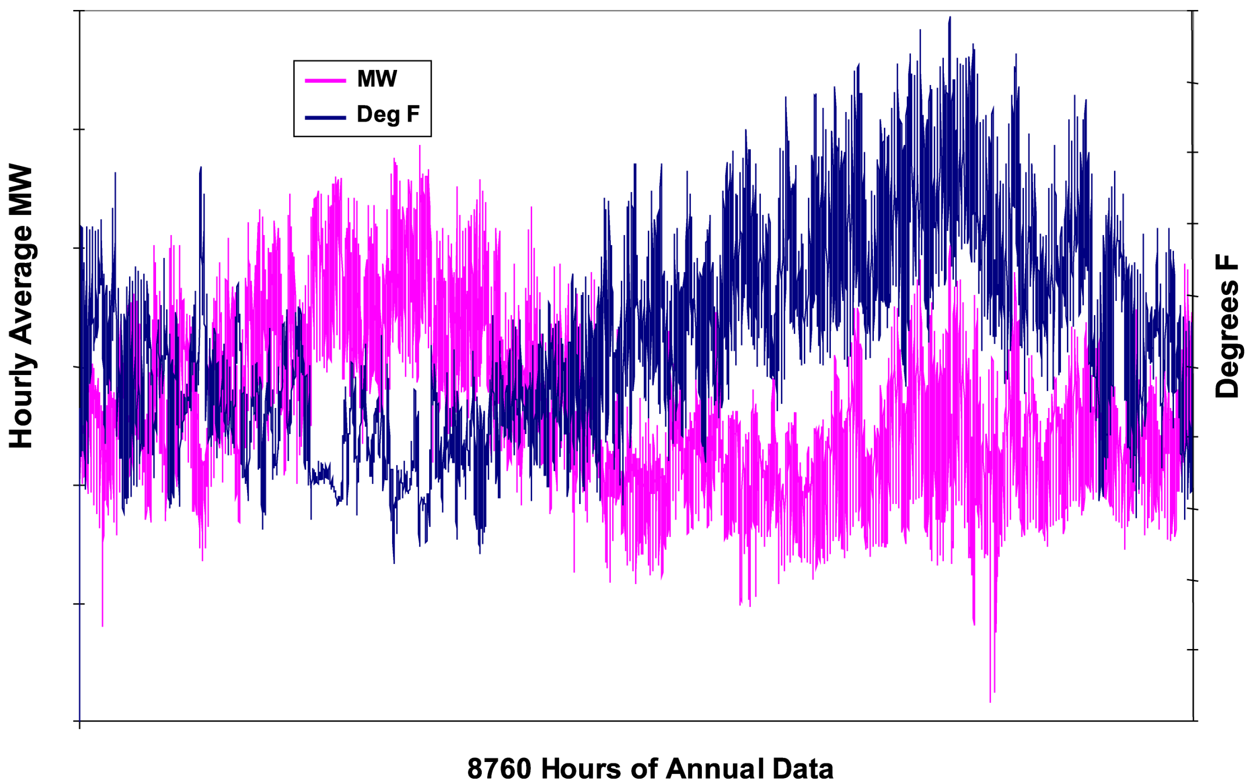


Figure 4-8
Typical PUD Total System MW and Ambient Temperature Relationship

This might look challenging enough by itself, but fails to show the full story. Figure 4-9 shows that in a week of winter data, each day typically has two peaks, morning and evening, with each peak being very dependent upon the outside ambient temperature.

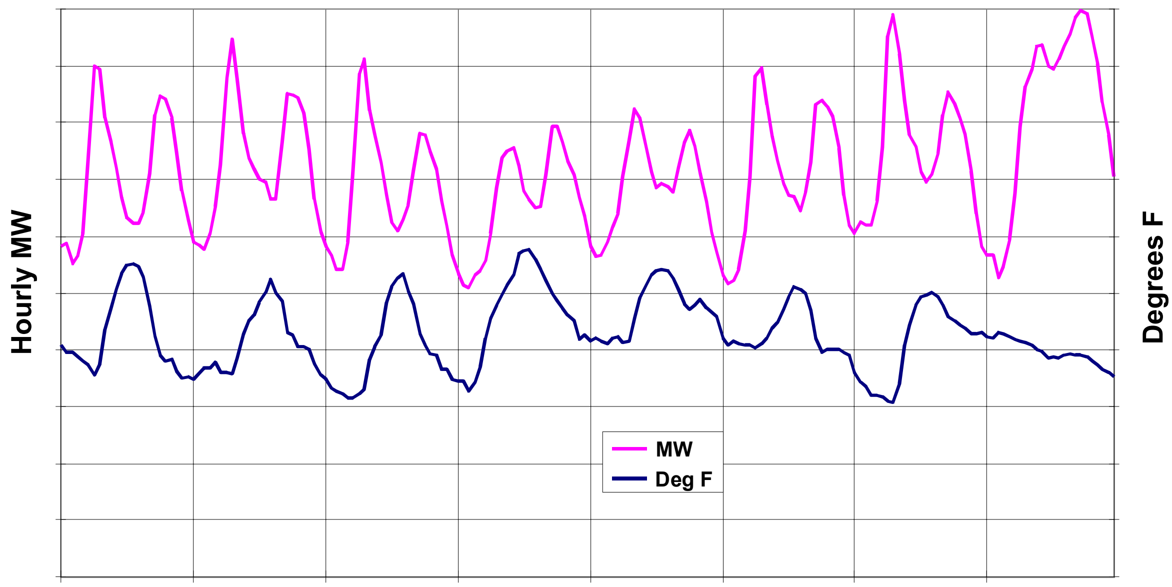


Figure 4-9
Total System Electrical Load and Ambient Temperature Showing Twin Peaks per Day in Winter

Demand response can be and has been requested and exercised by regional energy companies twice a day, by estimating the economic benefit for both mornings and evenings and showing customers those offers. Notice that the morning peak tends to be the worst, but not always. Day-ahead weather forecasts are reasonably accurate, so energy companies are pretty good at that, but the snap back (recovering the water heater energy displaced) effects of demand reductions can be troubling if energy prices have not subsided in the hours following the event. Otherwise, the energy company could pay for demand reductions in the four hours of early morning, and then see higher loads in the subsequent four hours due to the recovery of the electric heating loads. If the wholesale prices had not returned to normal lower levels, the customer would not have actually saved the energy supplier anything (and might cost the supplier imbalance penalties).

Reliability and system stresses, along with contractual capacity agreements, are different economic parameters than the one just described. Value determination is left to the one buyer who can acquire the demand trade at this point. Worth is defined by what someone will pay for it. The point here is to be especially aware in these temperature-sensitive situations about the entire load shape actually served with demand trades in comparison to the one served without. Moving energy from high-priced periods to low-priced periods is the goal (even if the loads snap back). Some loads do not snap back (such as lighting) and thereby have none of the associated settlement risk.

Demand Response Can Help Reduce Price Volatility

While criticisms of generators withholding capacity to drive prices have appeared in the news, it is even more interesting that the New York State ISO heard complaints from generators that the ISO's demand-trading program was going to drive prices down! Avoiding costs that no one documents as avoided is trapping many energy companies into financial ambivalence about demand-trading mechanisms. EPRI's pricing studies repeatedly illustrate that even small amounts of elasticity in customer demand substantially reduce the final price intersection between the supply and demand curves in regional spot markets, as Figure 4-10 indicates. Said another way, not using demand response causes the settled price in regional markets to be higher than it would otherwise be.

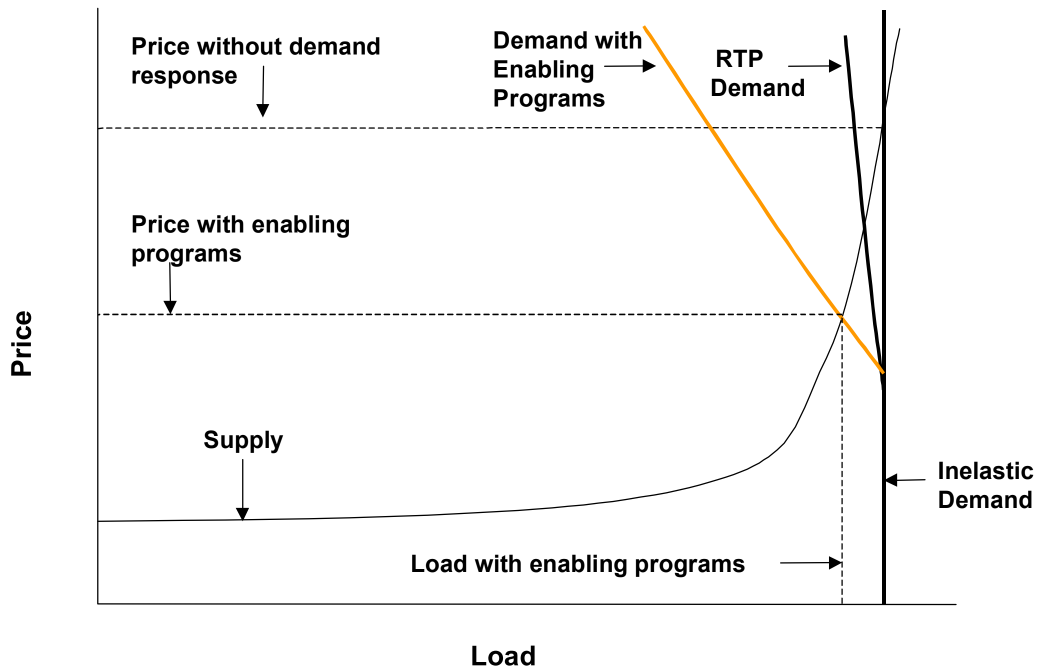


Figure 4-10
Effects of Enabling Programs on Wholesale Market Prices

In addition, if the energy company has any depth to their spot market purchases, influencing the final clearing price downward not only reduces that incremental transaction, but the remainder of their purchases in the spot market as well. For example, assume an energy company has 300 MW spot market purchases without demand response and 250 MW with demand response. Also assume the clearing price for the 300 MW would have been $250 per MWh and, because of the demand trades, the final clearing price is $200 per MWh. The customers producing the demand response would share in the final clearing price of $200 per MWh. The statement that the energy company shared 50/50 is rather misleading then. The benefit of the demand trade was to drop spot market transactions to $50,000 per hour from $75,000, for a modest 50 MW reduction. After paying the customers for their 50 MW at $100 per MWh ($5000 per hour) the net value for demand reduction is $20,000 per hour for 50 MW, or $400 per MWh.

Realize the numbers used in this example are illustrative, but the effects are real. There is more value than the incremental transaction would indicate and giving the customer 50% of the incremental settled price offers the energy company significant benefit (again, if their spot market depth is larger than the demand trades themselves).

Profitability Risks and Cost Recovery Models

Where the energy company simply passes on the wholesale-incurred costs to customers anyway using some form of fuel clause or rate schedule adjustment, the primary savings achieved through demand trading are:

- Costs that are not immediately recovered through rates due to regulatory lag, and the associated time value of money in accrued underpayments
- Prudence challenges that forward agreements were used and useful
- The image value costs and benefits of forward price stewardship

The second issue has the potential for significant value if the energy company is going in for a general rate case. If that company had neighbors who had used customer demand trades for price stewardship and had significantly smaller rate impacts, there might be some adverse results to the rate case. For example, imagine a long-term payment was made to large customers to reduce electric demand, essentially shutting the plants down over multi-year periods. Also assume that the price paid proved to be significantly above market. If that company went in for a rate case to recover this cost, it could be criticized as being imprudent and the requested cost disallowed.

The flip side of this was exactly what initially trapped the California market. Long-term forward price agreements were likely to be deemed imprudent if the collective opinion about spot market prices being cheaper proved to be true. The fear of imprudence and the popular belief that spot markets would be reasonable trapped the IOUs into the short-term markets for all of their electricity supply needs. This was fine when prices ranged from $20 to $30 per MWh, but proved catastrophic when the markets went into constraint and prices spiked.

The third issue in the list deserves thoughtful consideration. Price stewardship is part of the image an energy company portrays to its customers, regulators, and stockholders. Being a good steward of forward prices would include taking those actions that are in the best interest of customers over time, which might very well include customer demand trading even if the rewards are unsure. As a result, phrases such as “doing the right thing” replace attitudes like “what’s in it for me” in the discussion and presentation of demand-response mechanisms.

The Value of Customer Education and Readiness Tests

Call options come the closest to capacity agreements. Experience in the energy industry indicates that educated customers who are exercised yearly in this relationship (that is, there is at least one call on their participation) typically produce 85% or more of their aggregated claimed demand-response capability. Those who are rarely exercised more typically produce 60 to 75% of the capability the first day they are called, and significantly less as the consecutive calls are exercised. A lot of that depends upon the quality of the relationship and care taken in customer acquisition, education, and event notification.

This capacity is not without a cost, and that cost can be significant. Call options that go unexercised expire worthless. Therefore, they can prove to be expensive. Voluntary demand-response options are not expensive, because the buyer hasn't prepaid for them—they didn't cost much to acquire. On the other hand, the call option can prove to be quite inexpensive when it is used to avoid high market prices. To some extent, the combination of customer demand diversity and the effects of high prices make some level of voluntary demand-response firm. How much? That depends. Which is better? Neither. They are both part of a portfolio.

The experience of existing large demand-trading programs is extremely relevant here. They comprise a portfolio of programs assembled over decades, that include all forms of voluntary and involuntary demand trades. They have aggregators at work externally to bring resources to them at offered price signals, and aggregate their own programs of demand-trading relationships. The result in any one area can be a portfolio exceeding 1000 MW of potential, with the firmness of that resource depending upon price offers in the market. Their wholesale trading interfaces know where the price points are, and communicate accordingly. They have learned, through experience, how much of the voluntary demand-trading resource is firm based upon prices offered. There is no substitute for this experience.

Not everyone has been so successful. The key reasons for these failures involved a lack of attention to the following principles:

1. **Educate customers about your programs:** Customers do not speak the trading language and are easily confused and disappointed as a result. Keep all structured programs intuitively simple, use plain English, and limit the number of choices to four or fewer. Don't expect the customers to sign up without workshops to explain the program options, and offer specific examples of how they can participate in each program offered. If your organization does not have the staff to do this, hire those who can.

2. **Educate and test customer-specific capabilities:** Customers who learn how to respond to these agreements perform well over time. Run readiness tests to help customers develop easy procedures to follow. Spend time with the customer personnel who have to make demand-trading work at their site to show them what their load shape looks like and how their demand-response capabilities show up on the meter.

3. **Educate customers about markets and relationships in markets:** Most customers do not understand regional energy markets and the trading and risk management challenges they present. The inefficiencies in these markets make trading their demand response tricky. When customers see the impact of these challenges on their businesses, they will better understand the economics of these demand-response relationships, and the reasons for the structures. Otherwise, they will assume the energy company is not telling them the whole story.

When all is said and done, each energy company will have to consider its optimal portfolio of customer demand-trading options. And, if the energy company's portfolio is too small to trade directly into markets, they should consider aggregating that portfolio with other regional players.

5
MEASUREMENT, VERIFICATION, AND SETTLEMENT

The purpose of this chapter is to illustrate how the art and science of measurement, verification, and settlement (MV&S) is typically performed and the degree to which errors and uncertainty can be managed in the process. Another purpose is to offer the typical warning signs of customers who are either prone to unfairly benefit from claimed demand-response actions or might actually game the situation assuming the energy provider wouldn't notice or challenge them. Please do not become resentful of the obligation to check into this. Demand trading is no different than any other efficiency and load management program. The energy company has the obligation to eliminate free riders to the best of its ability (especially if it expects regulatory approval for cost recovery).

If performing this due diligence is unfamiliar, potentially damaging to customer relationships, or too labor intensive to perform yourself, outsource it. But it must be done. Outsourcing has the added advantage of helping the customer see the scrutiny as fair and equitable because the outsourced provider should have no reason to benefit from the size of the demand response. It takes the same amount of work to review one day's reconciliation for a customer who offers 100 kW as the one who offers 100 MW in a demand trade. That is why the most common compensation for this service is based on a setup fee plus some amount per customer-event reconciliation.

Issues in MV&S

Some demand trades are easy to measure with confidence-metered grid-isolated generators, photovoltaic panel outputs, and so forth—what you see is what you get. The buyer and the seller are not likely to disagree over the data. But how do you measure something that didn't happen? Lighting circuits and other end-use loads can be measured, but how do you really know whether the customer turned them off due to price signals? Could the customer have turned them on in the hours ahead of the trade so they would appear to have been turned off in the trade?

These uncertainties have led some energy companies to refuse to consider demand trades beyond metered generator resources. Others set criteria for demand trades that restrict a customer's options to approaches that would look like a generator in their ramping and steady state characteristics. Creative energy companies draw few distinctions, but might pay different prices for demand-trading resources, much as they might pay differentials on the supply-side. At this time customers are generally trading demand response to just one buyer. Therefore the issue is largely a private agreement—whatever measurement baseline works for both works. As markets open and customer demand response is traded to multiple buyers, the details will matter.

The industry has no standard for demand-response measurement as of this writing. There are some very common models in use in the United States and around the world, but they are all flawed for certain customer load shapes. There will be an evolution to these techniques. Aggregation does significantly improve the confidence counterparties can have in knowing they bought what was given. One might summarize by stating this is currently an art, not a science.

In any event, this all boils down to the confidence you can have in predicting what the customer would have done with and without price signals on any given day. If you could predict with perfect surety a customer's load in a given hour without a price signal being offered by examining what the customer did with a price signal, you could accurately estimate demand response against a given price. The key ingredient is the level of assurance that the customer did what they actually did in response to price, and wouldn't have done it anyway.

Interestingly, this is an issue that is still unresolved after 20 years of trying. If the customer is down from natural causes, but is ready to come back up during a time of concern, wouldn't you want to pay him not to come back on the system? Extending this concept leads to the consideration by some that maybe it's all right to pay them anytime they're down regardless of the reason, just as long as they're down when you want them to be. In any event, some customers can offer quite a bit of assurance while others offer less. Because this is a key trading risk element, it will certainly have price recognition over time. At the moment, ironically, little recognition is given, perhaps because there is so much art to the process at the moment.

One common example of a significant energy company concern is how to properly credit customer maintenance actions and plant shutdowns. In most situations, these actions are scheduled months in advance to be sure the maintenance crews, welders, rigging equipment, and so forth are all coordinated. They are commonly weeklong events once or twice a year. They should be factored into the energy company's forward plans in any event, even if prices are not expected to be a concern—knowledge of these load decreases improves forecasts.

What about the customer who decides to perform unscheduled maintenance in response to a high price offer on a voluntary demand trade? How can the energy company be sure they didn't simply bid in what they were already going to do? The treatment of this situation seems to depend upon the quality of the relationship the energy company has with the customer and the openness the customer has to share internal communications and documents. Some of it is nothing more than trust (with verification, of course). One would also certainly suspect any customer who only participated in the demand-response program once a year and claimed to perform unscheduled maintenance.

It is important that the energy company point out in the customer agreement what is and is not an acceptable customer action in response to price offers, along with the rights the energy company believes it needs to assure itself of true customer price response. Some energy companies differentiate between customers who operate unmetered, grid-isolated generators and those that have metered, grid-isolated generators, believing that the metered generator is the only sure way to know what the customer would have otherwise imposed on the system. A few moments of thought about this should point out the obvious fallacy. If the customer saw a high enough price offered for demand response, they would simply load up the generator with everything they could run just to get the credit for load reduction.

The How To (and How Not To) of MV&S

First, the good news—measuring something that didn't happen is actually easier in some situations than you would at first imagine. Now the bad news—it is much harder to measure something that didn't happen in some situations that would have seemed to be easy. Part of the reason for this is a mistaken confidence in traditional customer billing parameters that causes discussion of customer energy use to take on a misleading level of either fear or confidence. It is commonly expressed in the following phrases:

1. **The customer has the same demand, energy use, and load factor each month:** The assumption implicit in this statement is that aggregate monthly parameters imply consistency in load shape. They do in certain situations and mean nothing in others. Predictability in the hours of each day that are expected to be demand-responsive is what matters, not load factor or even billing demand, and the reverse is also true. Just because the customer has highly variable demands and load factors doesn't mean it is a bad candidate for demand-trading programs.

2. **Erratic load shapes are bad candidates:** This isn't true either. Erratic load shapes require statistically extracting the demand-response signal from the load shape. Do not analyze the mean or standard deviation. Analysis of the demand-response signal in relation to the noise level in the customer's baseline indicates what the statistically significant demand response limits should be in a program.

For example, Figure 5-1 is a comparison of daily load profiles from a PUD in the Pacific Northwest that curtailed water heaters twice on one day. The comparison is made relative to the previous day and several other proxy load shapes.

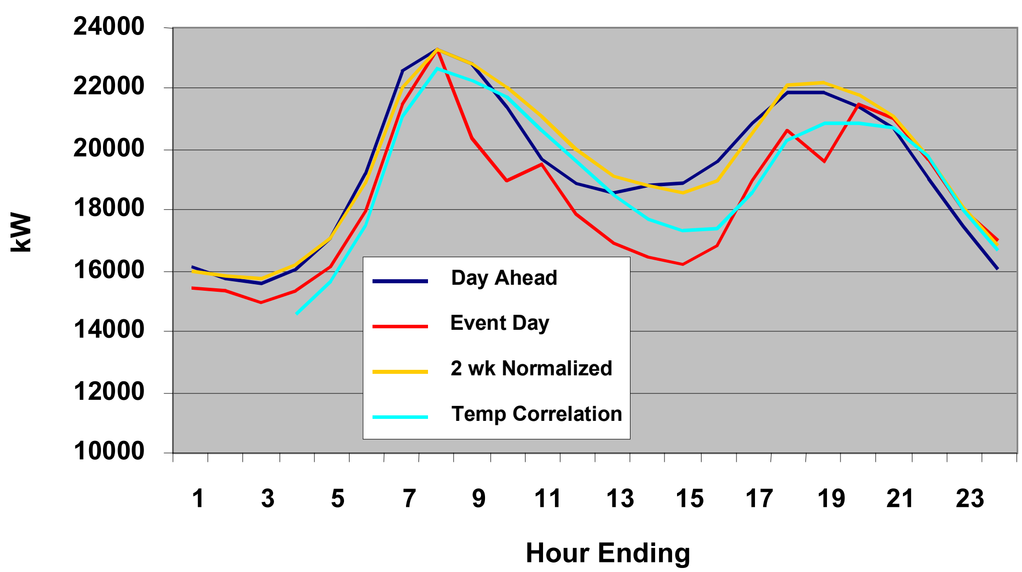


Figure 5-1
Comparison of Methods

One can certainly see that the event day has two notches in it, thereby verifying the PUD did curtail loads. The critical question is by how much and how much should they be credited for having reduced? This measurement and verification step must have several attributes:

1. **It is intuitively appealing:** Averaging the previous two weeks of nonevent days has this appeal, but is certainly not dependably accurate for weather-dependent loads.

2. **It is computationally inexpensive:** Data requirements to weather-correct loads are potentially costly, and the complexity of the analysis baits customer scrutiny. It is all too easy to spend more time on verification and discussions about weather corrections with customers than the event is worth. This is similar to the company that spends millions of dollars on administrative procedures for thousands of dollars in petty cash vouchers. It would be cheaper to use the honor system.

3. **The customer accepts it as fair:** At the end of the day, this is about striking a bilateral agreement, not a game of cat and mouse. Not all customers are the same. Not all measurement, verification, and settlement procedures need to be the same.

Most traditional curtailment programs offered customers incentives to get down to a given "firm demand" level—meaning one that is intuitive, computationally easy, and seems fair. However, customer loads tend to increase over time and getting down to that same fixed level year after year tends to get more difficult. This is certainly only fair to both parties, given that the customer is getting an increasing benefit over time in the rate design's standby incentive, but if there are penalties for nonperformance, the customer service implications should be obvious once the agreement is exercised (and the customer is unable to perform as expected).

Some of these programs had phrases like "get down by" a given amount where the demand before the curtailment period was connected to the demand after the curtailment period with a straight line drawn across the demand reduction chasm. Customers were supposed to get below that line by their contracted amount. Given that most customers will begin demand response before the event period to be sure they are down, this depresses the starting point, and the same is true at the end of the period. This type of verification strategy is simply going to result in customers claiming unfair treatment because it is neither intuitively appealing nor fair.

Going back to the PUD illustration, you can also see that part of the problem in this specific situation is that the loads would have been expected to fall at or about the same time of the day (based upon typical load shapes from days prior). The good news is that it is clear that the event day did have two curtailment actions. The bad news is that, outside of some arbitrary hand fit to the data, the credit for those reductions is debatable, especially given the method this energy company was using to curtail was radio-controlled water heating with known "snap back" recovery with uncertain kW impacts in the period following curtailment.

There is a myriad of ways the event day could be compared to some baseline, but each of them has a fault. There is no perfect solution, especially in the case of the PUD situation shown, because the load is an aggregate of thousands of underlying customers, and there is an intrinsically erratic pattern within this signature. For example, comparing the event day with the day-ahead load shape, it does seem that the event day is similar in the early mornings and the evening—but the departure during the middle of the day is disturbing. Notice that the day-ahead was also very similar to the two-week normalized load shape (where each hour of the day was averaged and then the kWh in each day was equalized). Once again, notice the difference between these curves in the middle of the day, during which there appears to be a sag in the day-ahead and even greater sag in the event day itself.

This analysis took a full year of temperature and load information and created a detailed correlation of each day of the week with temperature. That curve is also shown in Figure 5-1. That seemed to catch the second curtailment action in an intuitively appealing way, but why did it miss the first curtailment so badly? No one has been able to ascertain just what was really going on in this situation.

As noted above, at some point you can spend more effort trying to be accurate than the accuracy is worth. This PUD deserves less for their demand-trading actions because their actions are harder to verify and the kWh are merely shifted to a later time in the day (where prices might not be much lower).

Going back to the discussion of the standby generator, the kWh generated do not show up at a later time, and the verification is rather conclusive. Figure 5-2 is an excellent example of a commercial building with a standby generator. The customer pledged four hours of curtailment in the afternoon, started the generator shortly before the first hour of the trade (to be sure it operated reliably) and then turned the generator off and resumed utility service shortly after the event period ended.

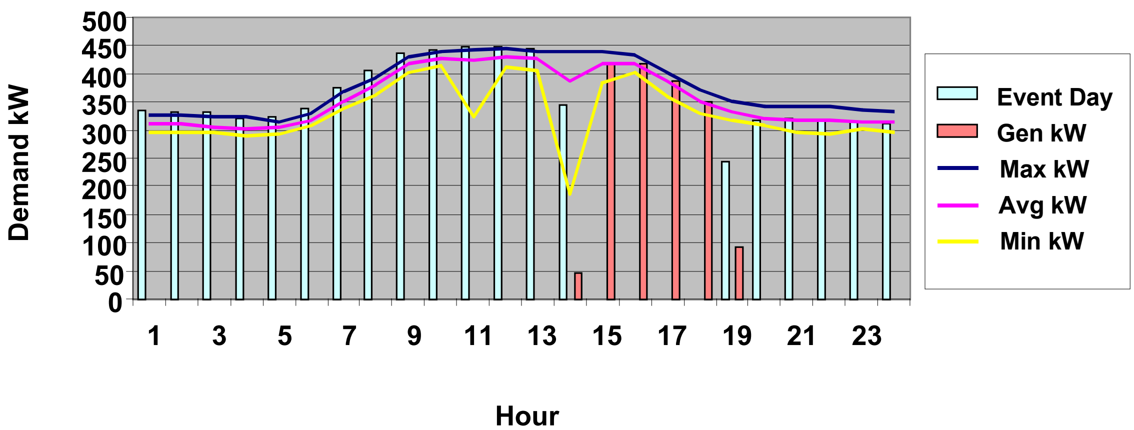


Figure 5-2
Demand vs. Time Example

The customer-generated kW were inferred and not directly measured. They were calculated from the average of the two weeks of non-event data preceding the event day. The event day kW for each hour is shown and you can clearly see that the customer disappears from the grid shortly before the four-hour mid-afternoon event, and then reappears right on the average for the previous two weeks after the event period. The highest and lowest hourly average demands for each hour of the day are also shown. Notice how tight this band is for hourly highs, lows, and averages. That characteristic is rather common in many commercial customer accounts. The combination of small variations in hourly demands plus significant demand reduction makes this a relatively easy and intuitive account to verify.

It is very important to work with this customer to shape their perceptions and expectations the first time this customer pledges to reduce demand. The standby generator in this case was 1 MW, and the customer might have otherwise pledged that reduction (over twice the highest demand the generator could offset). In this customer's situation, the serving energy company permitted demand response to be different in each hour, and each hour of their response was compared to pledge and liquidated damages were applied for under- and over-delivery. If the customer did not know its average load shape during those hours, it is likely that this customer might have pledged inaccurately.

This also points out a trading rule that some forget. Traders might want the same response in each of the four hours of this trade. It might not be possible for the customer to give them that because their load shape is not steady during those four hours. How should the customer bid? Is it fair to charge customers for their load-shape variations in the four hours? Should higher prices be offered for customer with flat load shapes in these hours? These are all fair questions, but ones that should be settled between the load-serving entity and the customer when the customer is signed up and runs a readiness test on their capability, not after the customer first attempts to curtail for real.

Figure 5-3 is another example of a commercial building that simply turned off perimeter lights for the same four-hour bid period. The demand response effect can be seen clearly.

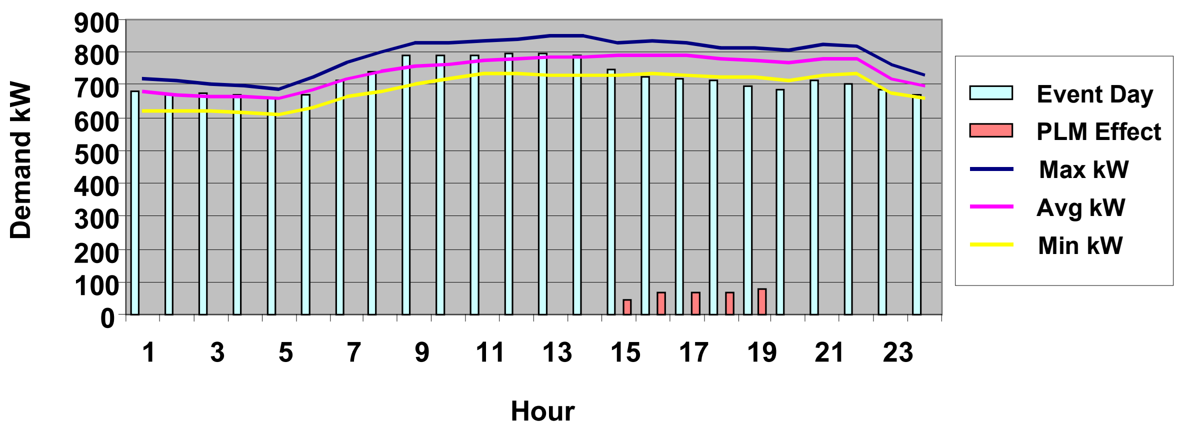


Figure 5-3
Commercial Building Example

Notice they left the lights off for the remainder of the day after the event period. The person who turned them off went home for the evening. Why not! By the way, because the remaining hours of load reduction were neither pledged nor accepted, they were not credited to the customer.

Not all customers are so predictable in their demand-trading capabilities. Figure 5-4 is an example of an industrial customer who claimed to turn off a 400 hp pump in hour 16. Can you see it? Would you give them credit for it? One option would be to request more historical data and perform a statistical confidence evaluation on this event. But at some point the analysis and likely questions customers will ask obscure the benefits.

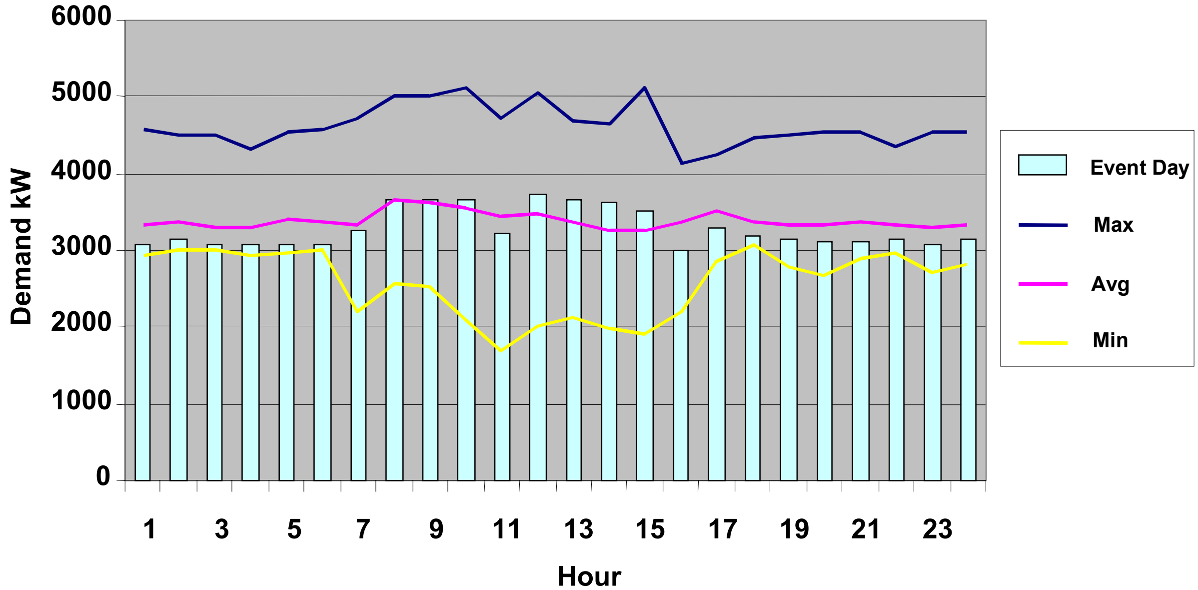


Figure 5-4
Industrial Customer Example

Clearly, the signal-to-noise ratio of this customer is inferior to the prior ones. Why is that? Simply, the day-to-day and hour-by-hour variations of this customer's demand are much higher. Therefore, it is not about peak demand, load factor, and average load shape (which is rather flat in this customer). It is all about the patterns of variation in the hourly periods and the discernability of the customer's action when cast against that pattern. It has to do with signal-to-noise ratios, and not the traditional metrics energy companies use in billing cycles.

A standing joke is that you can drown in a lake that averages two foot deep, and that the average American is half male and half female. In the same way, the average demand might not be an operating condition. Figure 5-5 shows four weekdays in a row for a customer who operates one base load operation and periodically operates a second production line several times a day. Does the average mean anything? What credit should the energy company give this customer for the curtailment of that line shown in the latter part of this week? It is clear that they curtailed the load, isn't it? Or, did the customer simply bid in an operating condition they knew was going to happen anyway?

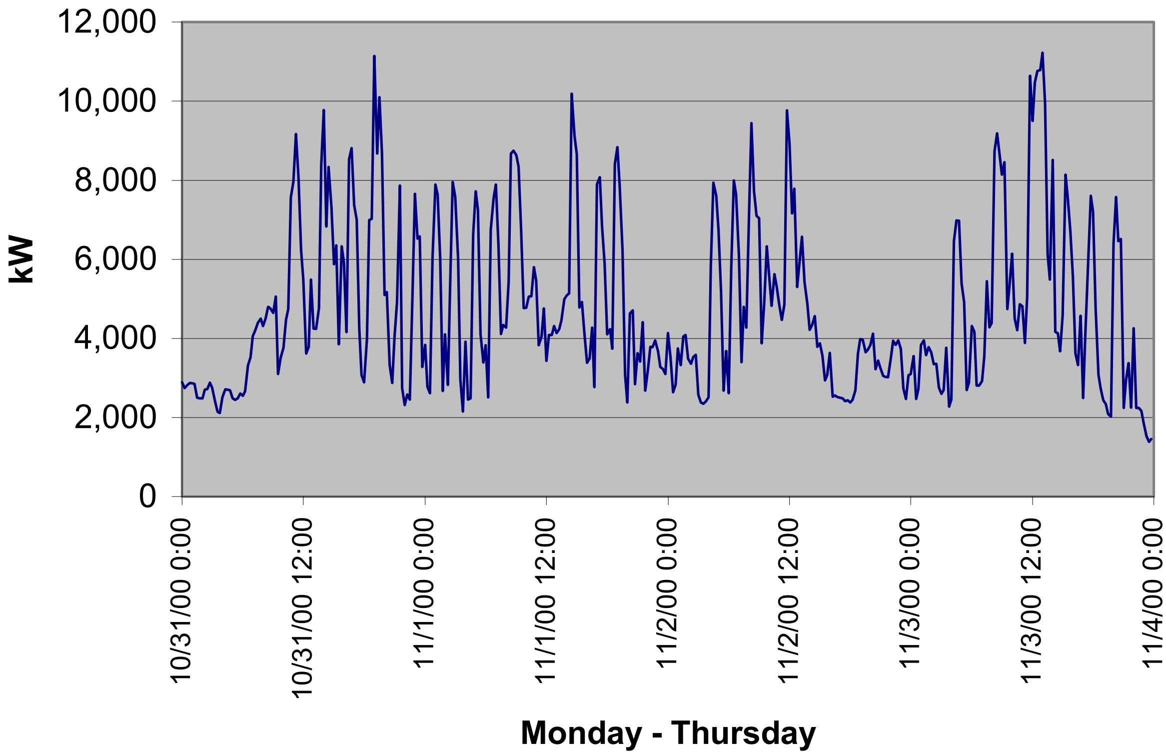


Figure 5-5
Example of Noisy Baseline

The final and reproducibly acceptable determination of this depends upon the quality of the relationship. If the customer participated in only one event in the season, and this was the one, they are quite likely to be a free rider.

Most energy companies correct the benefits paid to customers for demand-reduction trades if they are significantly less or more than what was pledged. Yes, you read that correctly. Producing more demand response than pledged is viewed about as undesirable as underperforming. The typical point at which under-delivery is corrected is between 75% and 90% of pledge. Shortfall kWh in each hour is most commonly debited against the credited kWh at twice the credited price. One could say the customer gets 50% of the displaced wholesale energy price for all kWh within the under-delivery and the over-delivery points and usually loses benefits at full market price outside of that band.

The reason most energy companies debit for overcorrection is that they are neither long nor short in their market. They would not be able to sell what they didn't know they had to sell, nor buy what they would otherwise have thought they needed.

The calculation procedures to perform this liquidated damages correction are really rather simple, but the customer service and marketing implications are not. It is interesting to note that many energy companies with these seemingly punitive clauses have been extremely successful in signing up customers for their voluntary demand-response programs. What is unknown is how much more potential there was if they had not insisted on including this requirement.

While threatening loss of benefits from sloppy pledging is warranted, the energy company should look at actual experiences, and then decide whether their command and control concerns are appropriate. Recent experience has shown that the individual customer pledge versus actual performance might be a bit erratic, but the aggregated performance improves quickly once 10 or more customers are in the mix.

For example, Figure 5-6, a composite of six large customers from one event day, should comfort those who worry about how predictably customers can pledge. The individual pledge versus actual was not really very good (with most customers missing individual hours by 20% either side), but the errors tend to cancel out.

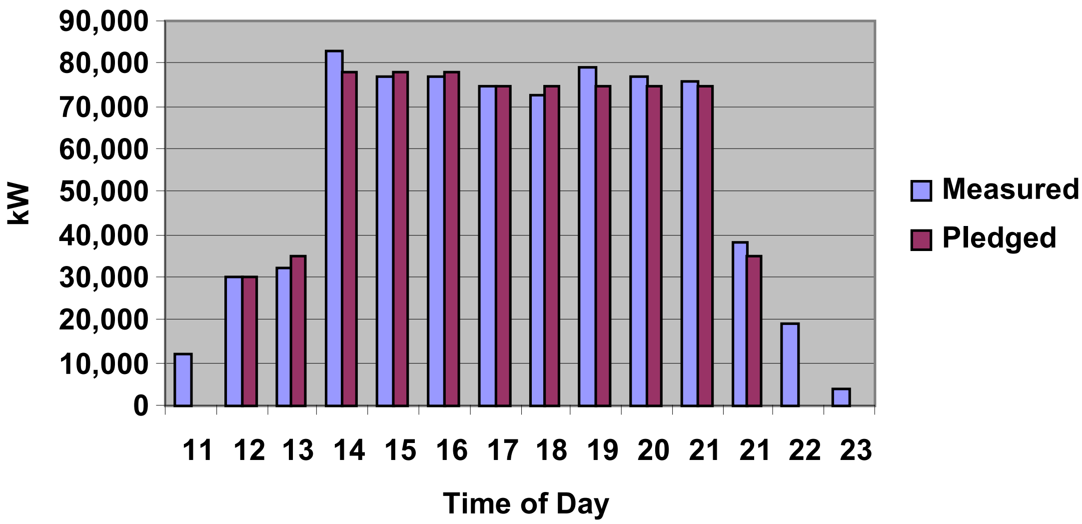


Figure 5-6
Composite Pledge vs. Actual

In addition, notice that there are free kWh reductions ahead of and after the pledge period in which prices were offered. Customers ramp down to their pledged condition and then ramp back to normal over an hour or so following the pledge period. Therefore, carefully shaping the price offer period can thereby encourage customers to give the optimal demand-response characteristics and produce an even greater value in trading. No record that anyone has taken advantage of this phenomenon is known at this time.

The best way to minimize the errors along with the customer service problems they might create is to provide customers with on-line energy information so they can see their baseline, and know against what they are about to be measured. While this sounds obvious, few of the existing demand-trading programs do that. Many customers are given no information to help them understand their baselines before they pledge. Because they do have some idea of what they can do from prior experiences in emergency situations, their pledges are reasonably good, especially in aggregate.

To be fair, there have been some complete changes of mind about this lack of information over this last year. Some customers now believe most energy companies will provide at least daily energy profile information updates to their customers in the next year or so. Flying blind is no longer comfortable to most, and the integration of demand trading into formal positions will require a more timely information flow than reading a meter on normal billing cycle schedules.

The most common frequency of information provided to customers is daily—updating their profiles once a day in the early hours of the morning. Day-ahead pledges would be missing the current day in the baseline day set (because it hasn't been read yet), but the errors here are normally small, because the baseline is shown for the average of the prior two weeks. The only reason it wouldn't be reasonably accurate is that the day on which the customer was considering pledging was far different than the average of the previous nine days. Energy companies serving regions where heat storms are rare and severe would have a challenge here and will probably have to weather-correct baselines anyway. One relatively simple correction has been offered in Appendix B of this report.

Several energy companies provide even better information to customers (and themselves) by interrogating the meters about once every 15 minutes on the event days during the event periods. With this level of feedback, some level of alert and alarm condition monitoring is possible. Customers failing to meet their pledge levels within the allowable under-and-over criteria can be notified do something about it before the hour ends. Customers should find this information valuable and be willing to pay for the enhancement. Customers unwilling to pay for it are probably not going to participate in the demand-trading program anyway.

6 THE FUTURE OF DEMAND TRADING

Perhaps it is obvious that demand responses will eventually be traded actively and integrally against supply, and will discipline prices in electricity trading as they do in every other commodity market. This will take some time—possibly even quite a bit of time. The actual time scale will depend on how quickly the supply-side for electricity trading works things out.

The demand-side is different from the supply side of course. In many ways it is better than the supply-side. The resource is already delivered, and in many cases it is nonpolluting. It comes in many forms and costs of acquisition, execution, and settlement. Demand trading also requires enabling technology that integrally links customer-acceptable demand-response mechanisms to the markets. Available technology is robust and is certainly not the limiting agent. There is much in the way of enabling technology here today that can do that including programmable lighting systems, HVAC controls, and so forth. Even at the residential level there is also a multitude of approaches ranging from smart thermostats to gateways in the home. These can all shape customer energy-use patterns automatically in response to price. Those technologies are already in place and, with an actively traded demand-response market, they would be more widely used and cost-effective. The limiting elements are the linkages to the energy markets.

Price itself does already differentiate customer demand response in some senses because most customers do not want to be inconvenienced to change behaviors for prices in the $100 and less per MWh range. Some do and will, but that is a small fraction of the potential market. How does one establish a vibrant demand-trading market? The limiting agent is the “Catch 22” of the apparent customer disinterest in energy choice and the intermittence of attractive market price signals that might change that attitude.

Can a particular organization that sees the long term make the leap of faith and use the logic “if we build it they will come?” If customers were eager to sign long-term agreements with retailers, there might be one. If customers would sign leases on standby generators with energy retailers as part of price-risk partnership agreements to operate them for their mutual best interests, there might be one. Energy retailers have tried this, but with limited success. Perhaps a company like Microsoft might respond to the looming energy shortage situation in the Pacific Northwest this coming winter and decide that they will develop the equivalent of ActiMates’ Interactive Barney so that home appliances can react to programming on the television and make this all possible at a low cost. It almost certainly won’t be an energy company in the United States at this time. Most of them are seeking to rethink and reshape their base business as the RTOs form and the realities of retail energy choice are made apparent in their own backyards.

The vision of what could be beyond the current incomplete deregulation patterns is clouded. If the changes in the natural gas industry as it went through deregulation are any guide, those who develop the skills to include demand trades as alternatives to supply and refine their procedures will gain a jump on the competition. Natural gas-trading mechanisms started with futures, added the trading of options a few years later, and then moved into more complex deal structures. Because many customers could switch between fuel oil and natural gas, demand-response agreements using that flexibility have become an integral part of supply pricing.

Rather than hypothesize about just what might happen over time, one can break this evolution into three required constituents of all mature commodity-trading activities and treat them individually (even though they are interconnected and cross-influenced):

- Market-clearing mechanisms will have moved from the many-to-one to the many-to-many model
- Relatively small demand responses can be aggregated and traded by virtually anyone
- Open protocols for measurement, verification, and settlement are realized

What will be next? It is hard to say how quickly these attributes will emerge over time, but the attributes will certainly be clear as they emerge. In this DTT these attributes are described in their broad categories: resource development, agent relationships, exchange liquidity, and arbitrage trading.

Demand-Trading Resource Development

As in any commodity, there is a limit to the resource. More can be harvested, but only after more seeds of opportunity are planted. This takes time. Customer demand response is the same. It takes a combination of information, technology, and experience to develop the demand-response resource. Customers have historically used generators and the option of turning things off as their preferred methods of participating in demand reductions. Those options are being rapidly expanded to smart thermostats in homes, programmable lighting, and market price-responsive interactive energy management systems.

Distributed generation technologies are being enhanced to include more environmentally friendly designs and cost-effective interconnection and control strategies. The result is that customer demand-trading resources are being expanded through technology and information, and are increasingly being linked to market mechanisms. This is going to increase customer demand-trading elasticity and make some higher hours of annual use strategies more attractive to customers and market participants.

For example, customers would never have agreed to demand-response strategies that would require hundreds of hours of annual participation. Most customers were unsettled even by the thought of a few dozen hours of exposure in a year. Enabling technology and creative financial partnerships will bring forth seasonal energy strategies (such as operating a cooling system on a dedicated generator and concepts such as thermal storage).

Any trading market depends upon more than technology and technical resources. It takes the acceptable standardization of trading instruments, and customers have been rather silent so far about what that means to them. How do customers want to participate in demand-trading markets? What should those instruments look like? How many shades of gray are survivable in an open market? This is somewhat like the automobile industry in the United States. Henry Ford started producing cars with the thought that you could have any color you wanted as long as it was black. In the 1950s, cars were being designed with custom rear axle ratios—clearly a bit too far in one direction. The 1970s saw a middle ground of standard offers. Now, car salesmen ask you what you want and try to find the car built that way.

This is not to say that more than three or four choices should be offered to customers. Choices should be formalized based upon a realistic expectation that they are the primary ones customers will agree to, and that they can be either aggregated into or directly used by wholesale market and regional reliability organizations as alternatives to supply.

Energy companies are currently making the same mistake that car companies made through focus group exercises and other means, to try to get to these answers. Customers were asked what they wanted, but were not being forced to be equally candid about whether or not they would actually pay for it. Energy retailers are finding the same thing when it comes to energy information. Customers say they want it, but these retailers then find they won't pay very much for it. A key part of this problem is the perception of value. If the information appeared to be valuable, either the customer would pay the price or authorize someone else to worry about it for them.

Therefore, developing the customer's demand-response resource will require education and acceptance on the part of customers to participate in demand trades—they need to see the joy of driving this new energy vehicle. One might suggest getting them into the market any possible way so they can experience it. As they try to drive further or faster, they will appreciate the comfort, power, and controls car builders can offer. Similarly, the buyers for customer demand response must truly become interested in their participation and not simply be thrown the supply-side bone—you can play too if you act like and look like a generator.

Demand-Response Aggregation and Agent Relationships

The energy industry has the opportunity to really get creative about who can drive on the energy highways. Most of the smaller customers would prefer to outsource their opportunity and will not want to engage energy markets directly. This will require reasonable rules and flexibility for aggregators to move in, something akin to busses as public transportation. The rules of the energy roads are just too complex and frightening to most customers. The analogy here would be "take the bus and leave the driving to us." Orderly rules for acquiring customers and bringing them to market are needed. No one wants the transportation circus of jitney drivers in Atlantic City who will cut each other off to pick up a potential fare. It would certainly be a more efficient energy transportation system if creative parties were allowed to register their business propositions and obtained a license to operate.

Demand trades are similar to supply-side trades in that they can provide multiple market values. Just as wind power typically commands a $20 to $30 wholesale price premium because it is viewed as a non-polluting resource, some demand responses are bound to earn a similar premium. They will do so because demand trades have advantages over normal supply channels even beyond the potential for emission credits:

- They are already delivered in the zones
- They might even have enough regional impact (in aggregation) to clear transmission paths

Virtually none of this added value is recognized today because demand trades position customers as price-takers rather than price-makers. That will certainly change over time. Agents and aggregators will bring the customer capabilities to the market, and let the markets find customers.

In addition, demand trades will eventually be graded and valued along a continuum, much like stocks and bonds. Some will be AAA rated, better than some generators because they are already delivered, and with environmental virtues as well. They will have measurement, verification, and settlement confidences that rival a gold standard. They will be credited with externalities and possibly even tax credits because they are deemed socially superior to any other energy sources (because they are negawatts and some of them are very green). Environmental credits are certain to be included in the value chain of some demand trades, even though no customer demand trades are included at this time.

It's even possible that there will be the equivalent of junk bonds in demand trading at the other end of the commodity quality spectrum. These resources might be of low quality but they will be priced so inexpensively that they actually make sense to trade. The buyers for this resource could simply be buying a cheap hedge in their portfolio, or might be trying to see if small, dispersed, and difficult to measure, verify, and settle demand trades add real value. In today's trading vernacular, these would be called dirty trades. They are a very real part of the supply-side perspective as this document is being written.

The first signs of this thought migration process are already appearing. Necessity is the mother of invention. Energy efficiency, load management, and price-responsive loads (under the umbrella concept of demand response) are all coming back into play as energy companies realize they might not be able to find or deliver adequate supply-side resources. The investment in demand response rightfully is (and always has been) in the portfolio. It will be interesting to see if the same interest spreads into seasonal demand-response strategies such as thermal storage and certain forms of distributed generation. Given that the needs might exceed 1000 hours of demand-response operation, it seems quite likely that this extension will occur.

Demand-Trading Depth and Liquidity

Part of what will be needed to move these paradigms along is the depth and liquidity of demand-trading markets of sufficient magnitude that the financial derivative instruments of risk management can be deployed as well. It is interesting to study the roots of the insurance industry and see just how that business developed. It was out of natural counterparty perceptions of risks that agreements were struck to cover the unlikely but devastating uncertainties of life. People recognized that they each had a small but frightening exposure to risks, and that by pooling those risks and sharing in the costs, there was a reasonable premium they could each afford. As the industry and market grew, high risk and low risk groups were singled out and priced accordingly. For example, today's smokers pay up to four times as much as non-smokers when they buy health or life insurance in open, competitive markets. Teenagers, often through their parents, pay more for automobile insurance than adults, and the list of differentiators goes on.

As energy price risks continue to emerge, be quantified, and studied, there will be similar price risk differentiations and derivative risk-pooling tools to mitigate those risks. Default price risk is now freely discussed as a deal killer, but was hardly mentioned when deregulation was first being implemented. Risks are often recognized fully only when bad things happen, and even those writing the insurance as a business must worry about the worst of things happening (such as the hurricanes that wipe out thousands of homeowners). That data is emerging, and the awareness of customer demand trading as one member of the risk mitigation portfolio is just now being understood. There will emerge a spectrum of price- and risk-differentiated products and services in the market over time, and the demand-trading aggregation will permit risk mitigation and rightfully deserved long-term premiums. Market participants will drive this, so the key underlying requirement will be the active operation of energy markets, especially at wholesale, but with increasing benefits as retail markets develop fully.

All of this does take time. Just as options in the future's market first required the liquid trading of futures to provide price transparency and volatility valuation, one will need to see longer-term valuations for demand trades that take us out of a day-by-day, season-by-season, year-by-year attempt at valuation. In a sense, one needs enough forward demand trading activity to entice large companies to make this market by taking indexed agreements for demand response that assure customers and their counterparties of what they can get for their demand trades each year. Fire, theft, and other insurance premiums are all formulated this way. As the energy price risk mathematics settles down, large market makers will provide the risk capital to fund large-scale customer demand-response portfolios.

In the language of the trader, these indexed agreements are called swaps—one party wants to eliminate price uncertainty and the counterparty is willing to take it. They are also called contracts for differences. One side takes the volatility on, while the other wants the constant valuation signal (and pays an expected-value premium for doing so). That will come, but it will take an underlying level of activity that is certainly not yet developed.

One of the keys to all this happening is true independence and diversity in the underlying energy market risks. Hurricanes do not strike all coastal areas in any one year—they only hit a portion of the coast each time. Price spikes, however, can now threaten very large areas of the United States. As the RTO concept replaces the ISO models and forms larger trading regions, price spikes could become more widespread and could occur in a time-coincident manner. That is precisely the worst thing for derivative instrument development; it drives the risk premiums in the worst possible directions (higher) because the events are not mutually independent. Therefore, under large RTO structures, price risks might not improve with aggregation (or at least not improve as much as had been hoped for or estimated). In a sense, the damage of any one "hurricane" in the emerging electricity market grows with the size of the RTO.

Hopefully, zonal pricing might keep the storm damage localized. If the experience of the PJM during the summer of 1999 is any indication, all zonal prices go to the cap when the regional market goes into congestion. Think about it this way: in the old world of energy regulation, the price spikes in California would have been localized. Now a problem in that region can spread to all neighboring regions. Price risks are thereby spreading. By itself, that is nothing more than market-clearing mechanisms at work. The point here is that one of the key economic underpinnings for large market-making insurance mechanisms to work is the statistical independence of underlying risk. Therefore, market makers might not enter this arena until adequate regional supply side resources are present. Only then would price spikes stay localized and the resulting diversity of this underlying risk would make it economically attractive for a market maker to take on long-term, demand-response indexed agreements.

Demand-Trading Arbitrage

Arbitrage plays a valuable role in all commodity markets. If the value of gold on a U.S. exchange and the value of gold on the European exchange differ by more than the costs of trading and transportation, people sitting at computer terminals watching these differences simply buy on the low exchange and sell on the high one. The trade they perform is called a risk-free trade because the underlying commodity agreements for the gold have no performance risk (they are guaranteed by the exchanges). The result of the arbitrage is that activity links world market prices while creating depth and liquidity to each of the exchanges.

By contrast, demand trading is not very close to this. At this time, individual energy providers either offer their own customers a price for the rights to call upon their demand trading capability, or offer a price for demand reductions in either individual hours or a block of hours. Customers will eventually look at multiple offers and decide which ones best fit their abilities or desires for risk. Some offers will be made with and others without liquidated damages. Some will have fixed blocks (for example, four hours at the same demand-response pledge), and others will permit individual hourly demand-trading responses. Some will have short-term notice, and others will ask for multiple-daily responses.

Similarly, customers under real-time pricing programs with undesirable wholesale price exposures will find counterparties (surrogates) to take their place who will agree to reduce demand on any one day for less than what the customer exposed to the real-time price would otherwise have to pay. Because the match between load shapes of the customer in the real-time pricing situation and the customer that was willing to offer demand response will not likely exactly match, aggregation and agents will once again likely be necessary to efficiently enable the trades.

This is all becoming easier with the Internet exchanges, but most of those exchanges are many-to-one models. Of course, there are exchanges that are true many-to-many models, but the wholesale electricity trading space does not yet easily enable cross-exchange deals. It will over time. As this occurs, it is envisioned that a new breed of arbitrageurs will emerge who will clear zonal and regional markets, arbitraging demand trades against supply. While these are far from the risk-free trades arbitrageurs typically use in currencies, the term is used because it has so much intuitive appeal as a cross-exchange trading activity.

The combination of aggregation and arbitrage will produce dramatic effects, linking wholesale and retail energy markets. For example, as natural gas-pricing moves from bundled daily and monthly allotments to hourly pricing in response to physical pipeline constraints, there will be a new type of cross-fuel arbitrage-natural gas against fuel oil and customer electrical use. Initially, it will occur along the model already being used to unwind natural gas contracts—getting customers to shift to fuel oil and relinquish their rights to purchase natural gas during the constraint period. As the generation capacity using natural gas during the summers finds time-differentiated prices for gas unattractive on those hot summer afternoons, they will buy the rights from customers for both reduction of electrical use and the customers' ability to switch to alternate fuels.

In Conclusion

Today's methods for trading electricity in open markets are inefficient and in transition. Do not be too critical—they are still in their infancy. This visioning chapter points out the possibilities once all energy trading moves to efficient market models. In today's markets, frustration can be so great that energy parties simply leave the table and do not play. However, those who play today will be better prepared to shape the path towards the future, and will have learned a great deal about counterparties and their perspectives in the interim.

Finally, consider one more parallel to the insurance industry. When life insurance concepts were first introduced, it was very difficult to sell policies to customers. This was largely because it was a novel concept at the time and because the policies were called what they were—"death insurance." The insurance industry learned a valuable lesson—watch customer perceptions. Now, almost all of us now carry life insurance.

How far away is the electric industry from the same conclusion and market response for the use of demand trading in electricity markets? Probably not very far. Time will tell.

A
EXAMPLE RETAIL ENERGY TRADING STRATEGIES

The wholesale trading desk of a retail energy company (REC) purchases a portfolio of energy supply resources at a multitude of times to meet the planned energy needs of its customers. Customer loads and prices have uncertainty and blending the portfolio to manage price risks associated with that "book" of energy agreements is complex. The questions are two-fold: 1) How can customer flexibility to reduce electric loads potentially create a win-win scenario for both the REC and the customers in the energy market; 2) What procedure should the REC use to be sure that customers are encouraged to participate only when and if the conditions are right?

One opening caveat is clear. REC **does not want to sell electricity to customers at prices lower than either:**

1. Prices at which REC has to buy

2. Prices at which REC could sell

Customers, however, will not participate in voluntary demand response at prices much less than $0.10 per kWh ($100 per MWh). If we assume that a 50/50 split of benefits exists between REC and the customer, that implies the market price has to be over $200 per MWh. While the likelihood of that price existing in the market is low, even a few hours at prices above $200 per MWh can produce a lot of red ink in a hurry.

With a base set of assumptions, it is important to see the set of conditions under which the supplier/purchaser partnership has little to no risk and where it has maximum risk. Everyone clearly understands the high-risk situations where the customers say they will do something and then don't. The REC acts on the assumption that they will and suffers financially. While it is clear that such situations require extremely careful contractual considerations, it is academic when it comes to working with customers. Customers generally aren't interested in, or willing to take, the risks of being punished when something goes wrong in the market.

Some energy companies learned this lesson with their real-time pricing programs. In some cases, customers thought they could reliably operate their generators, but faced higher than anticipated prices when their generators failed because their energy companies had to buy the energy for them at high prices during the Summer of 2001. The energy companies simply passed through the purchases at market. Everyone must reconcile the fact that attempting to pass the full risk on to customers will simply result in no partnership possibilities—the customers will simply shop the fixed price agreements and take the low price offer. Look for those situations where the risks are minimal and think creatively about benefits optimization.

To that end, here are a series of go/no-go gates. Any time the first gate opens, the process moves to the next gate. It is assumed that customers would only be notified about the demand response opportunity when the gates are in a "go status." That is the way this process is organized.

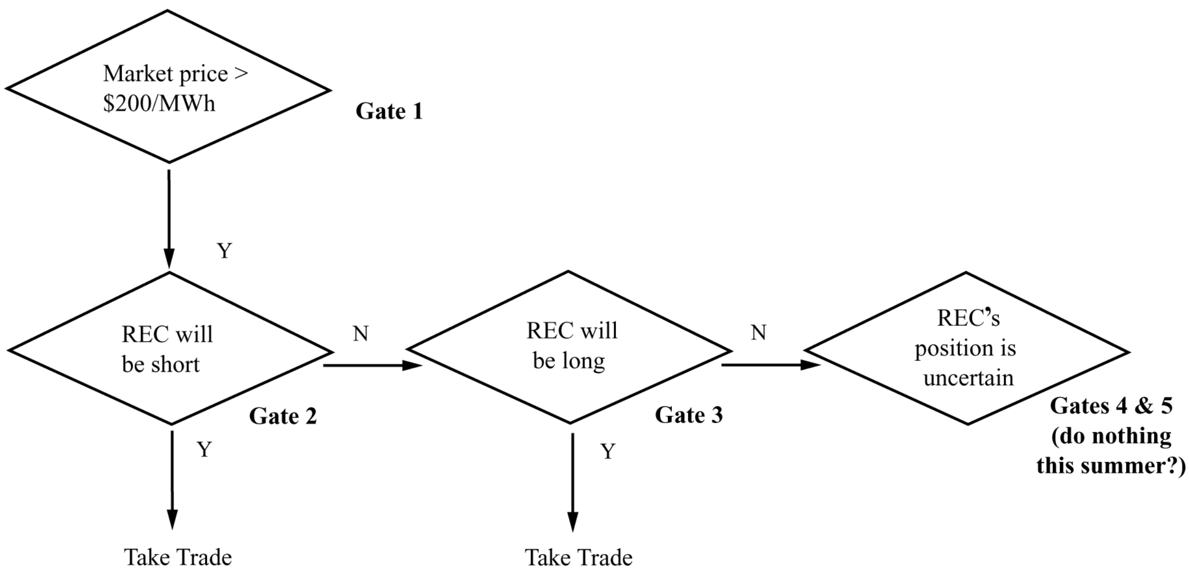


Figure A-1
Simplified Flow Diagram

Gate 1: The price for power tomorrow is expected to be above $200 per MWh

The participating customers would receive an alert at this stage that the credit they could earn toward future bills (or to fund their revolving demand-response account) is at least $0.10 per kWh. A 50/50 benefit sharing arrangement is assumed here. Larger customers with significant generators could get more, others less. The alert indicates the expected times of the day when that price is anticipated tomorrow. Customers with generators would probably run the generator any and all of those times. Only those customers with easy demand-response options would exercise them. Obviously, the higher the prices, the more likely customers are to take more aggressive actions.

Gate 2: REC would have to buy power at those market prices

Demand response is not expected to significantly reduce loads for this coming summer. In many ways, the attempted pilot program is exactly that. However, any demand response that reduces energy purchases in this situation has clear economic merit. So, this is the most likely of all situations. If REC is short, demand response is unlikely to put REC in a long position.

However, if some customers served by REC could see regional market price opportunities, it is conceivable that extremely high prices in the market could cause some customers to take draconian measures.

If Gate 1 and Gate 2 are "yes" then anything the customer does to reduce load results in savings. While the amount of the savings are uncertain, and will require careful analysis of both the customer's true demand response actions plus actual settled market prices, there is no savings risk. REC is clearly reducing losses. The only question is by how much.

Gate 3: REC was already clearly selling into the market

The assumption here is that REC was already long and any demand response on the part of the customer would only add to that long position. The imprecision of the customer's demand response could put REC at some risk because REC has less than perfect information about just how long they are. However, it is also obviously advantageous to REC to sell less to the customer at the normal contract under this condition. Therefore, if REC discounts the expectations of actual demand response implemented, it seems that the risk of having too much to sell can be managed.

These risks of native load uncertainty can be managed in several ways. For this coming summer, one could probably simply take half of what the customers say they will provide as demand response (that will be proven during readiness tests). REC could also train customers to be more dependable by giving them a progressive portion of the benefits they provide. For example, customers might only earn 50% of the market price when they repeatedly demonstrate demand response reliability. This concept is similar to the way insurance companies lower premiums for customers who prove they are a lower risk. Do not be cavalier about opening Gate 3; be creative.

Gate 4: REC would have been buying and could now be selling

There are several ways one could go about this evaluation, but the easiest way is to start with a perfect control situation where customers would be punished if they failed to act predictably. The problem with this is that customers wouldn't likely sign up for such an agreement in the first place. The other extreme is to simply block customers from participating by not letting this gate open. That's fine, except for the fact that the market price is above $200 per MWh. The initial reaction is to block this gate shut for this coming summer and until sufficient demand side elasticity data are assembled to manage this risk.

Gate 5: REC would have been selling and could now be buying

Here the demand response achieved was insufficient for REC to meet all obligations and REC found itself buying in the hour-ahead market at undesirable prices. To one extreme, the penalty for this could be placed back upon customers who failed to perform by deducting these costs from their accrued credits. However, the question of blame is tricky. What constituent errors, who was the culprit, and how much blame should be placed on the customer? The initial reaction is to block this gate shut for this coming summer and until sufficient demand-side elasticity data are assembled to manage this risk.

B
CUSTOMER BASELINE DETERMINATION

The following is a summary of the approved procedures followed in the California Energy Commission's voluntary and demand bid programs for 2001.

The Customer's "baseline usage" is defined as the level of energy consumption that would have been expected in the absence of the Customer's agreement to reduce its energy consumption using the Demand Exchange® platform. It will be determined as follows:

1. The previous ten "representative days" of consumption will be averaged for each of the twenty-four hours in a day using the Customer's metered and recorded energy consumption. This includes averaging 15-minute intervals into hourly intervals.

2. "Representative days" exclude Saturdays, Sundays, national and/or state holidays, and days on which the Customer reduced energy consumption pursuant to any other program, whether an interruptible service tariff program offered by the local utility, incentive contract with the local utility or any other third party, or rotating outage effected by the local utility. Specific days known to be abnormal for the Customer (that is, where the Customer shuts a facility down for a week to permit vacations) will also be excluded from the baseline computation.

3. The highest and lowest hourly energy consumption for the days included as representative days will be determined and graphed along with the average hourly energy consumption computed in Step 1 to show the hour-by-hour variances included in the hour-by-hour average energy use.

4. The hourly average data for any demand reduction test or actual event-day performance will be compared to the hourly average, minimum and maximum energy consumption measured for the days included as representative days in the Customer baseline usage.

    a. If, on the day for which the Customer pledged a demand reduction, the Customer's hourly energy consumption in aggregate for the hours **not** included in the hours during which the Customer pledged a demand reduction is lower than the highest and higher than the lowest energy consumption measured for the days included as representative days, the baseline computation described in Step 1 will be deemed to be fair, reasonable and representative.

    b. If, on the day for which the Customer pledged a demand reduction, the Customer's hourly energy consumption in aggregate for the hours **not** included in the hours during which the Customer pledged a demand reduction is either higher than the highest or lower than the lowest energy consumption measured for the days included as representative days, the Customer's usage will be deemed to have been in part affected by a variation in the weather and the baseline computation described in Step 1 will be adjusted as follows:. The average temperature In these cases, a baseline correction will be determined by comparing the average temperature and the per-day energy consumption for the five hottest (where consumption is above the highest average) or coolest (where the consumption is below the lowest average) days with the overall average of the past ten days as follows:

i. Where the Customer's hourly energy consumption in aggregate for the hours **not** included in the hours during which the Customer pledged a demand reduction is higher than the highest energy consumption measured for the days included as representative days, the average hourly energy consumption for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, and the average high temperature for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, will be determined using the ten representative days and denominated as the variables "kWh_{10}" and "$Temp_{10}$." Next, the average hourly energy consumption for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, and the average high temperature for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, will be determined using the five hottest days among the ten representative days and denominated as the variables ("kWh_5" and "$Temp_5$"). The weather effect on the customer's load is the product of the following calculation: (kWh_5 - kWh_{10}) divided by ($Temp_5$ – $Temp_{10}$) = kWh/day per degree above average. This weather-effect factor will be used to correct the event-day baseline.

ii. Where the Customer's hourly energy consumption in aggregate for the hours **not** included in the hours during which the Customer pledged a demand reduction is lower than the lowest energy consumption measured for the days included as representative days, the average hourly energy consumption for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, and the average low temperature for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, will be determined using the ten representative days and denominated as the variables "kWh_{10}" and "$Temp_{10}$." Next, the average hourly energy consumption for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, and the average low temperature for the hours included in the hours during which the Customer pledged a demand reduction, in aggregate, will be determined using the five coolest days among the ten representative days and denominated as the variables ("kWh_5" and "$Temp_5$"). The weather effect on the customer's load is the product of the following calculation: (kWh_5 - kWh_{10}) divided by ($Temp_5$ – $Temp_{10}$) = kWh/day per degree above average. This weather-effect factor will be used to correct the event-day baseline.

5. The average weather and per-day weather variations shall be determined using values reported by the National Weather Service for the weather monitoring station nearest the Customer's location.

Demand Bidding Program (DBP)

Participant Guide

DBP Participant Guide

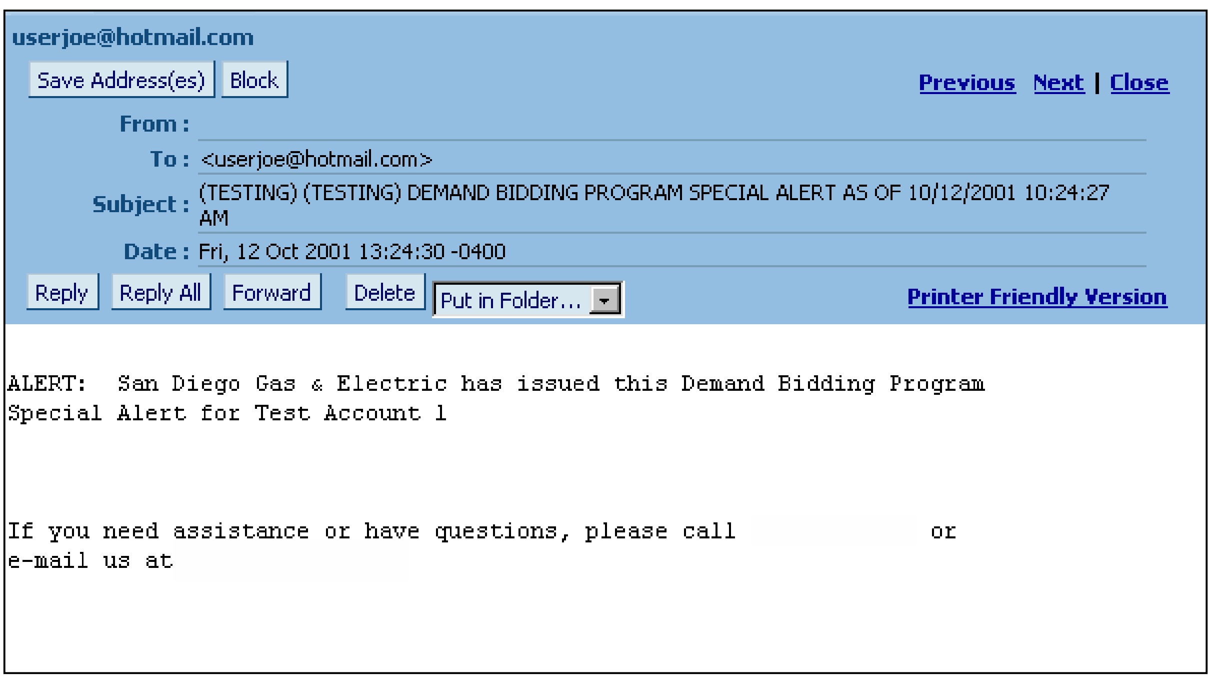
The following Demand Bidding Program Participant Guide will walk you through the process of pledging a load reduction for the Demand Bidding Program (DBP). The program is designed to help alleviate the need for rolling blackouts and other energy constraints by making additional load available.

To participate in the program, you will need a User ID and password, which will be provided to you upon program enrollment.

Bids must be finalized and submitted to SDG&E by 1 p.m. the day before a load reduction occurrence. SDG&E will notify you of bid acceptance or rejection on or before 5 p.m. that same day.

ALERT NOTIFICATION

There might be times that you will receive a DBP "ALERT" e-mail notification message from SDG&E similar to below.



userjoe@hotmail.com

Save Address(es) | Block | Previous | Next | Close

From :

To : <userjoe@hotmail.com>

Subject : (TESTING) (TESTING) DEMAND BIDDING PROGRAM SPECIAL ALERT AS OF 10/12/2001 10:24:27 AM

Date : Fri, 12 Oct 2001 13:24:30 -0400

Reply | Reply All | Forward | Delete | Put in Folder... | Printer Friendly Version

ALERT: San Diego Gas & Electric has issued this Demand Bidding Program Special Alert for Test Account 1

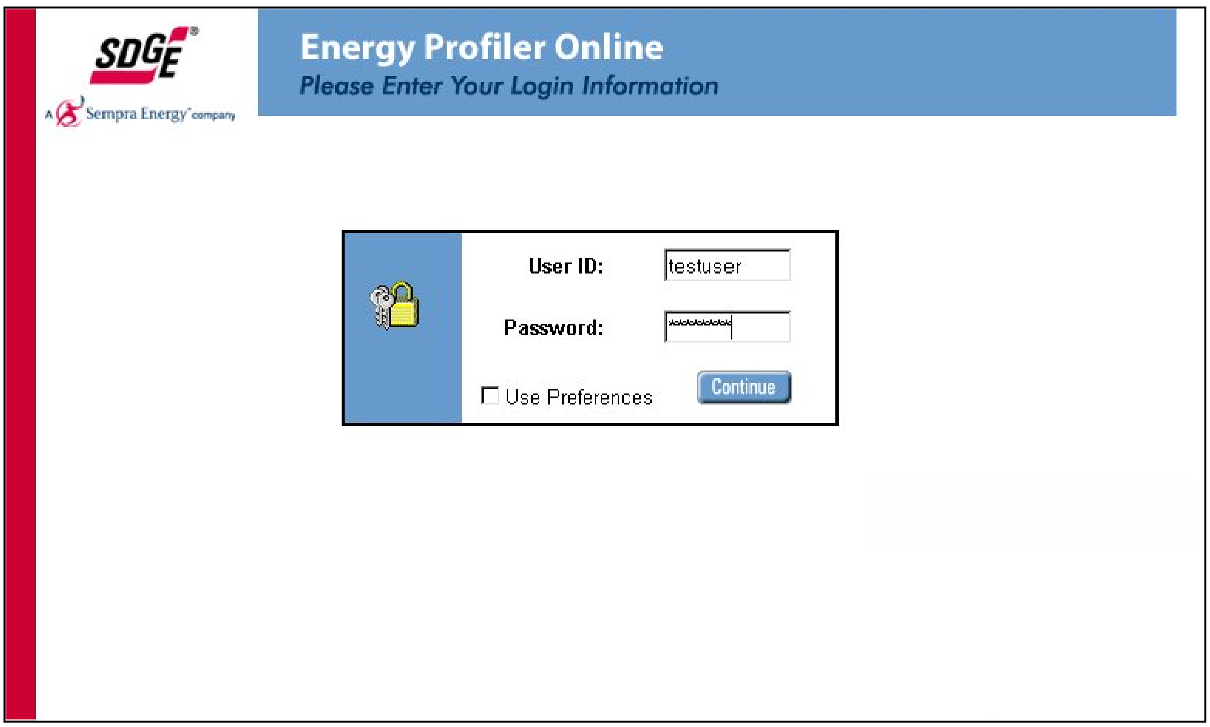
If you need assistance or have questions, please call or e-mail us at

DBP Participant Guide

STEPS TO SUBMIT A BID

STEP 1)
Using the Internet, log on to the Demand Bidding web site. To access the Demand Bidding section, click on Business/Demand Reduction Programs/DRP Participant.

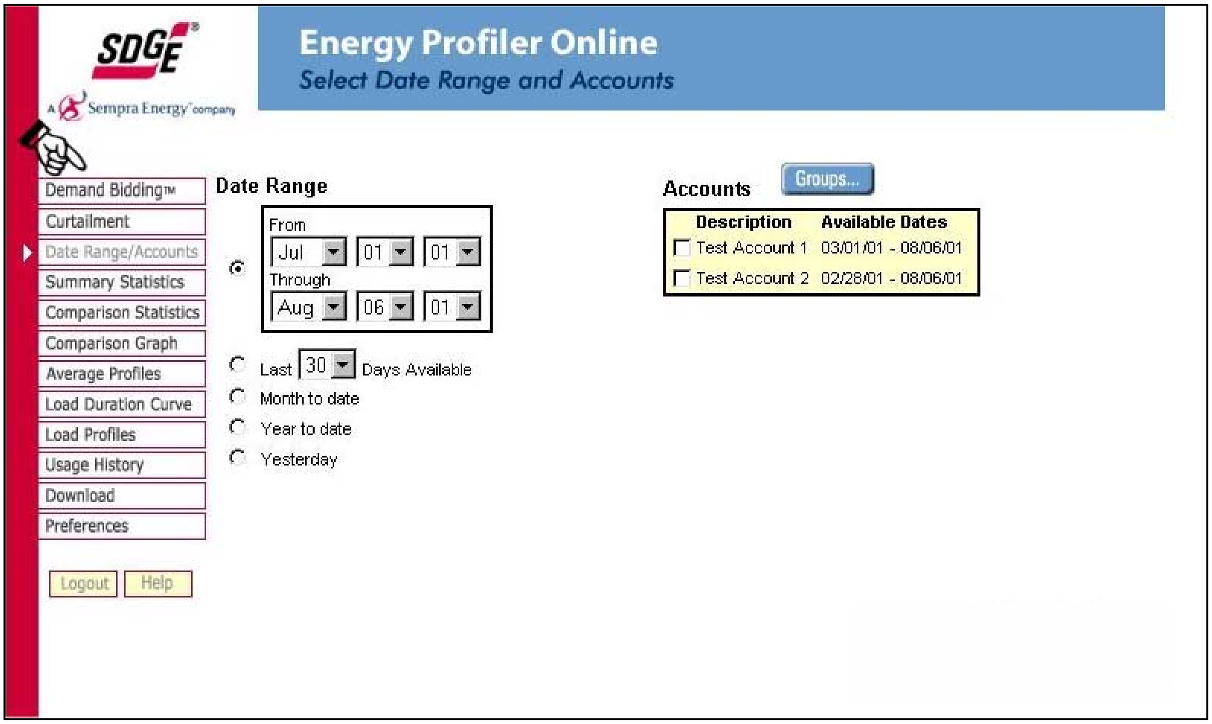
Enter the User ID and the password that you received when you enrolled in the DBP Program, then click **Continue**.



DBP Participant Guide

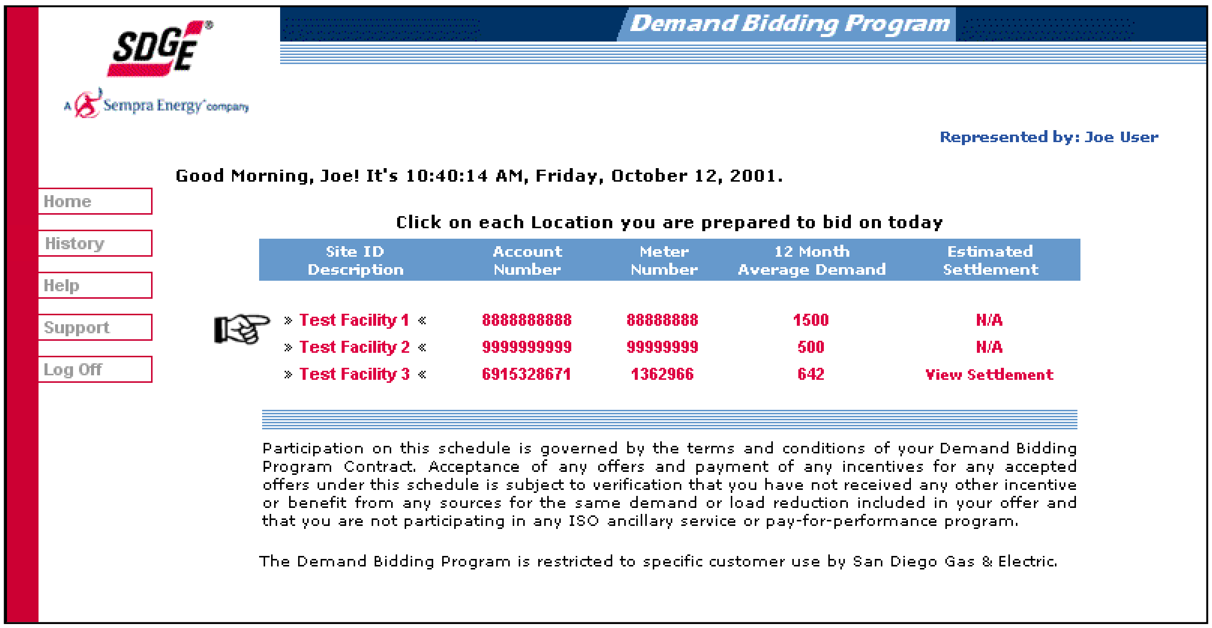
STEP 2)

To enter the Demand Bidding Program section, click on the **Demand Bidding** button at the top of the list on the left side of the screen.



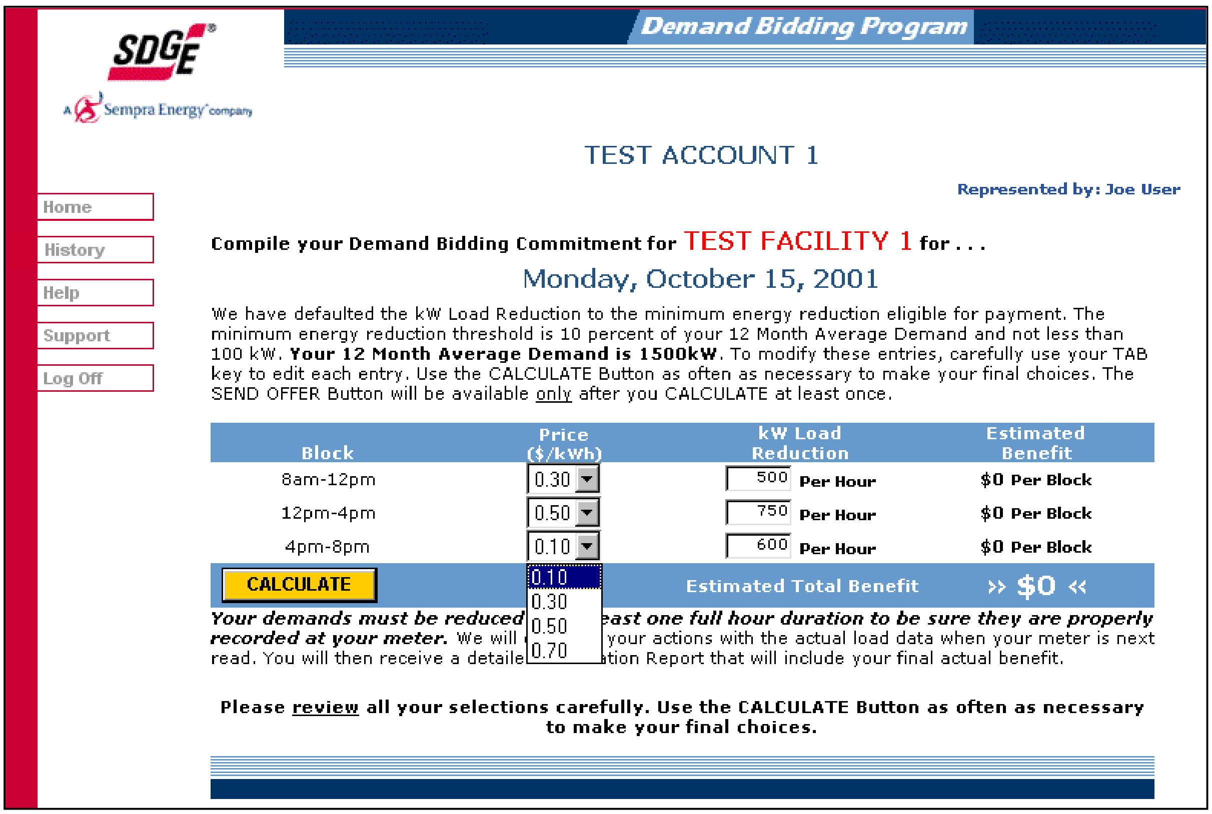
DBP Participant Guide

STEP 3)
To place a bid, click on each listing in the **Site ID Description** column for which you would like to pledge a load reduction.



STEP 4)

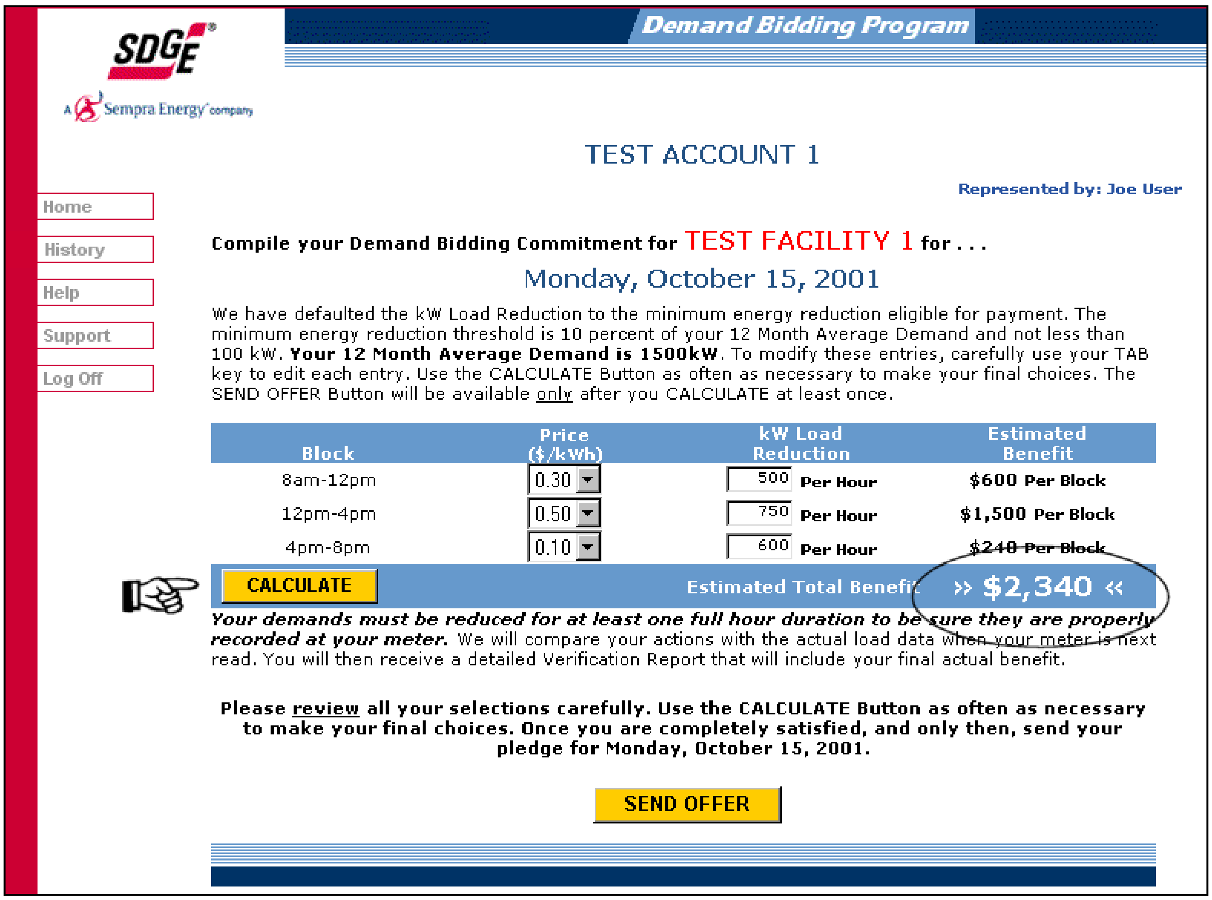
Review the tier of available bid prices and pledge your load reduction capability (**kW Load Reduction** column) for each time block you intend to participate. You can change the kW amount for each block provided it doesn't go below 100 kW or 10% of your average annual demand, whichever is greater. The price you select might or might not be the level at which your bid will be accepted.



DBP Participant Guide

STEP 5)

Once you have made your selections, click the **Calculate** button to review your estimated total benefit for the block of hours and load you have pledged. Modify your pledge and re-click the **Calculate** button as many times as you like to zero-in on your target **Estimated Total Benefit** and load reduction for that day.



Demand Bidding Program

TEST ACCOUNT 1

Represented by: Joe User

Home
History
Help
Support
Log Off

Compile your Demand Bidding Commitment for TEST FACILITY 1 for . . .

Monday, October 15, 2001

We have defaulted the kW Load Reduction to the minimum energy reduction eligible for payment. The minimum energy reduction threshold is 10 percent of your 12 Month Average Demand and not less than 100 kW. **Your 12 Month Average Demand is 1500kW.** To modify these entries, carefully use your TAB key to edit each entry. Use the CALCULATE Button as often as necessary to make your final choices. The SEND OFFER Button will be available only after you CALCULATE at least once.

Block	Price ($/kWh)	kW Load Reduction	Estimated Benefit
8am-12pm	0.30	500 Per Hour	$600 Per Block
12pm-4pm	0.50	750 Per Hour	$1,500 Per Block
4pm-8pm	0.10	600 Per Hour	$240 Per Block

CALCULATE Estimated Total Benefit >> $2,340 <<

Your demands must be reduced for at least one full hour duration to be sure they are properly recorded at your meter. We will compare your actions with the actual load data when your meter is next read. You will then receive a detailed Verification Report that will include your final actual benefit.

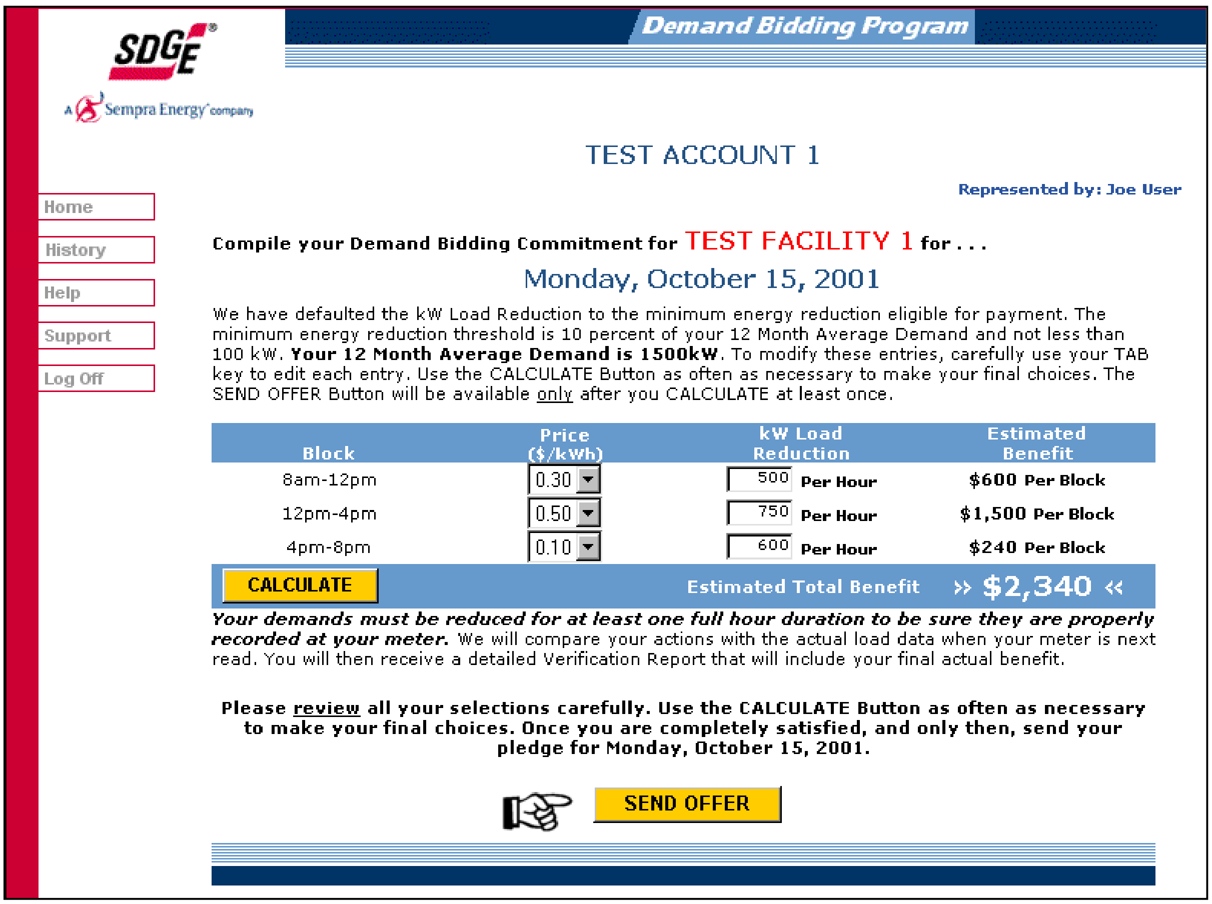
Please review all your selections carefully. Use the CALCULATE Button as often as necessary to make your final choices. Once you are completely satisfied, and only then, send your pledge for Monday, October 15, 2001.

SEND OFFER

DBP Participant Guide

STEP 6)
Once you are sure of your load reduction plan pledge configuration, click the Send Offer button at the bottom of the pledge page.

(NOTE: Do not click this button until you are ready to submit your bid offer!)


Demand Bidding Program

Home
History
Help
Support
Log Off

TEST ACCOUNT 1

Represented by: Joe User

Compile your Demand Bidding Commitment for TEST FACILITY 1 **for . . .**

Monday, October 15, 2001

We have defaulted the kW Load Reduction to the minimum energy reduction eligible for payment. The minimum energy reduction threshold is 10 percent of your 12 Month Average Demand and not less than 100 kW. **Your 12 Month Average Demand is 1500kW.** To modify these entries, carefully use your TAB key to edit each entry. Use the CALCULATE Button as often as necessary to make your final choices. The SEND OFFER Button will be available only after you CALCULATE at least once.

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4pm-8pm	0.10	600 Per Hour	$240 Per Block

CALCULATE   Estimated Total Benefit » $2,340 «

Your demands must be reduced for at least one full hour duration to be sure they are properly recorded at your meter. We will compare your actions with the actual load data when your meter is next read. You will then receive a detailed Verification Report that will include your final actual benefit.

Please review all your selections carefully. Use the CALCULATE Button as often as necessary to make your final choices. Once you are completely satisfied, and only then, send your pledge for Monday, October 15, 2001.

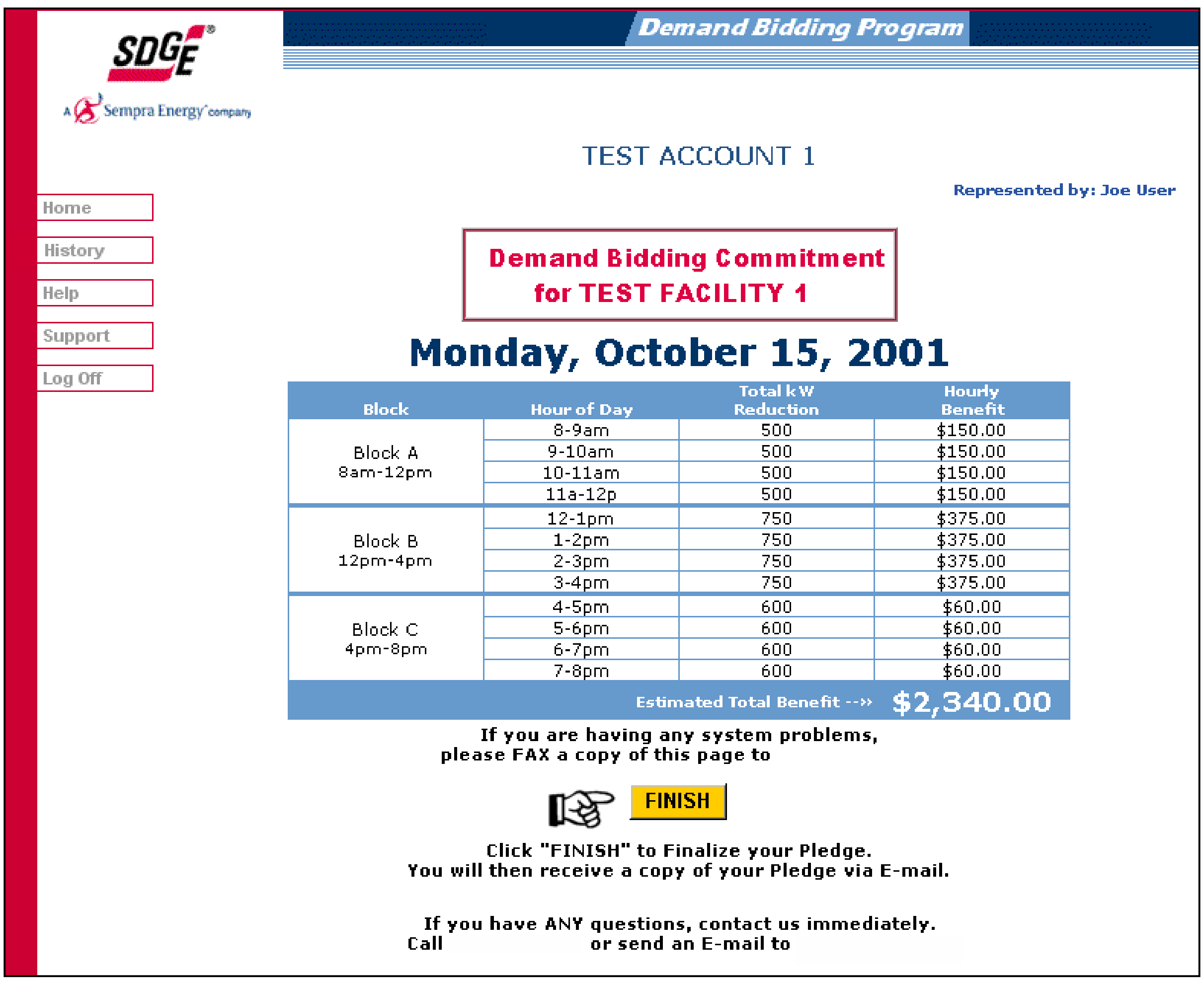
SEND OFFER

SDGE® A Sempra Energy company

DBP Participant Guide

STEP 7)
Once you have submitted your offer, you will see a detailed summary of the pledged load, by hour, time block and estimated benefit. This is your opportunity to review your pledge before your final submittal.

- If you are satisfied with your bid, click the **Finish** button to complete the process for that site location.
- If you wish to change or cancel a bid after it has been submitted, click on the **Home** button, re-select the site in question and you will be given an opportunity to Change or Cancel your bid.


Demand Bidding Program

SDGE® A Sempra Energy company

Home
History
Help
Support
Log Off

TEST ACCOUNT 1

Represented by: Joe User

Demand Bidding Commitment for TEST FACILITY 1

Monday, October 15, 2001

Block	Hour of Day	Total kW Reduction	Hourly Benefit
Block A 8am-12pm	8-9am	500	$150.00
	9-10am	500	$150.00
	10-11am	500	$150.00
	11a-12p	500	$150.00
Block B 12pm-4pm	12-1pm	750	$375.00
	1-2pm	750	$375.00
	2-3pm	750	$375.00
	3-4pm	750	$375.00
Block C 4pm-8pm	4-5pm	600	$60.00
	5-6pm	600	$60.00
	6-7pm	600	$60.00
	7-8pm	600	$60.00
		Estimated Total Benefit --»	$2,340.00

If you are having any system problems, please FAX a copy of this page to

FINISH

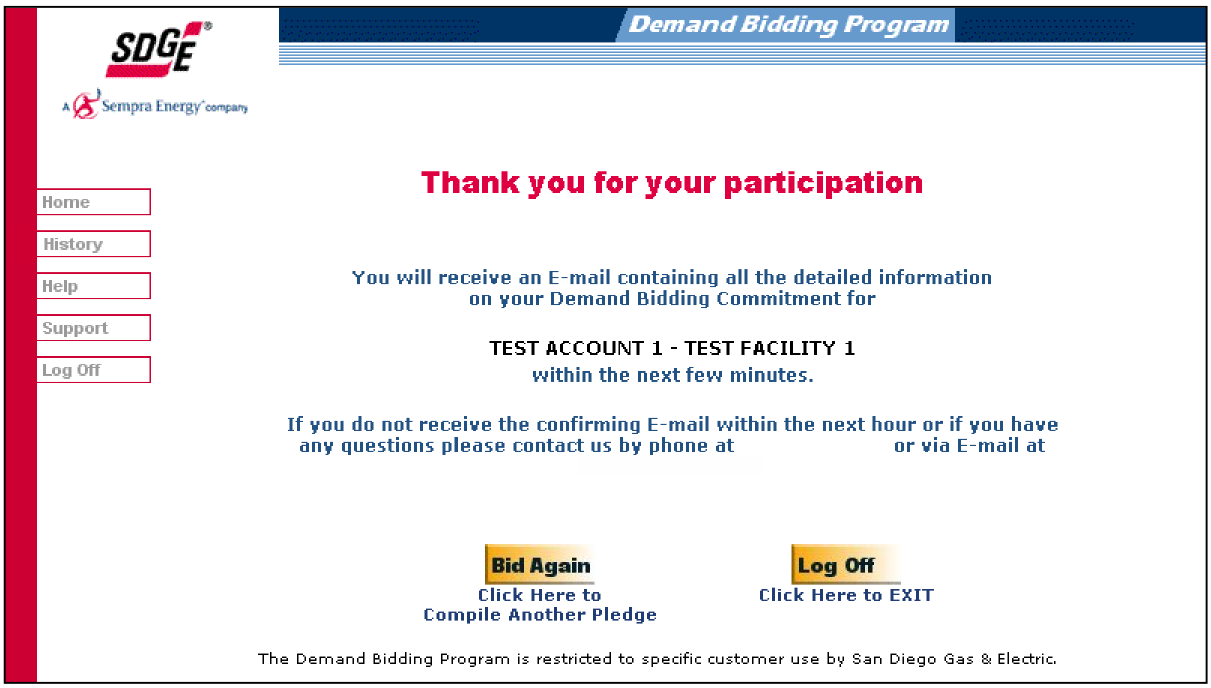
Click "FINISH" to Finalize your Pledge.
You will then receive a copy of your Pledge via E-mail.

If you have ANY questions, contact us immediately.
Call or send an E-mail to

STEP 8)

Once you have finalized your bid, the **Thank you** screen will appear. If you wish to submit a bid for any of your other participating accounts, select the **Bid Again** option. If you have completed bidding for the day, select **Log Off**.

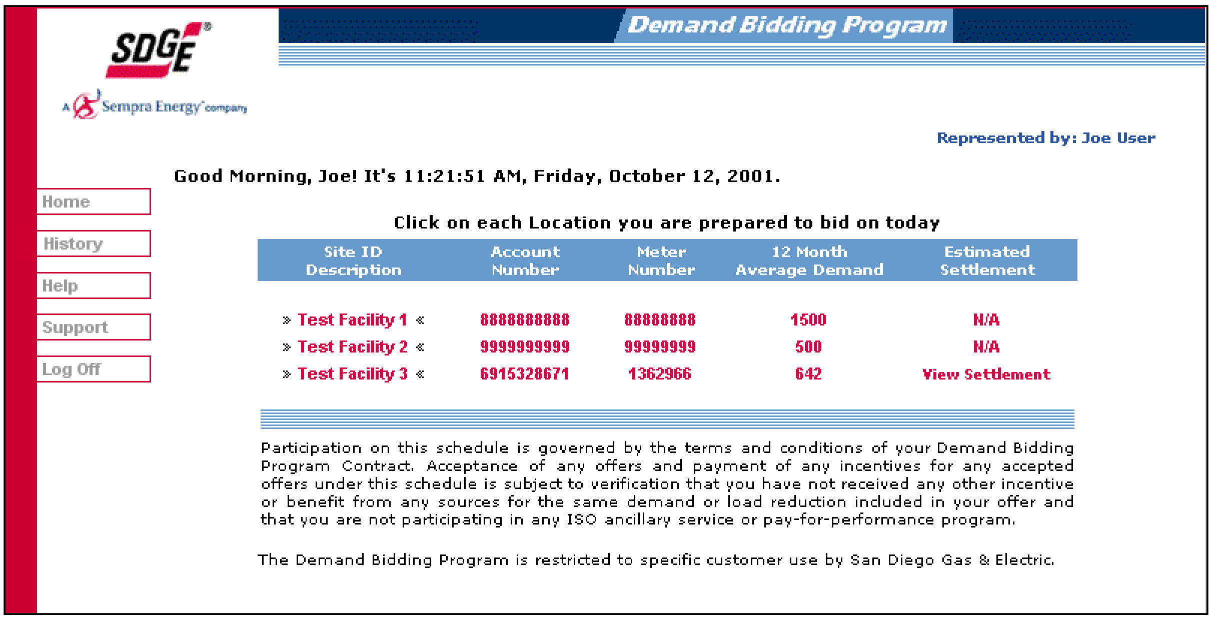
(Note: For bids to be considered, bids must be submitted by 1 p.m. the day before load reduction.)



DBP Participant Guide

STEP 9)

If you selected **Bid Again**, you will be taken to the first screen where you can select another meter for which you can submit a pledge. Repeat steps 3 – 8 for each **Site ID Description** you wish to pledge a load reduction plan.



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STEP 10)

Within minutes of clicking the **Finalize** button on each bid, you will receive an e-mail acknowledgement of your load reduction pledge in detail. This will be a final confirmation of your submitted hourly load reduction.

(NOTE: Your bid has not been accepted yet! You must receive an e-mail saying your bid has been accepted. Do not assume your bids will be accepted.)

userjoe@hotmail.com

Save Address(es) | Block — Previous | Next | Close

From:
To: <userjoe@hotmail.com>
CC:
Subject: (TESTING) Demand Bidding Commitment RECEIVED For Monday, October 15, 2001
Date: Fri, 12 Oct 2001 14:19:23 -0400

Reply | Reply All | Forward | Delete | Put in Folder... — Printer Friendly Version

```
Joe User,

On behalf of the California Department of Water Resources (DWR) and San
Diego Gas & Electric, thank you for your participation in the Demand
Bidding Program. The following lists the Demand Bidding Commitment as
pledged by Test Account 1 for Test Facility 1 scheduled for Monday,
October 15, 2001.  Please review this for accuracy.

The LOAD REDUCTION DATE is Monday, October 15, 2001

Block A
           8-9am   500kW Reduction @ $0.3000
           9-10am  500kW Reduction @ $0.3000
           10-11am 500kW Reduction @ $0.3000
           11a-12p 500kW Reduction @ $0.3000
                  Estimated Benefit for this Block - $600.00

Block B
           12-1pm  750kW Reduction @ $0.5000
           1-2pm   750kW Reduction @ $0.5000
           2-3pm   750kW Reduction @ $0.5000
           3-4pm   750kW Reduction @ $0.5000
                  Estimated Benefit for this Block - $1,500.00

Block C
           4-5pm   600kW Reduction @ $0.1000
           5-6pm   600kW Reduction @ $0.1000
           6-7pm   600kW Reduction @ $0.1000
           7-8pm   600kW Reduction @ $0.1000
                  Estimated Benefit for this Block - $240.00

                  Total Estimated Benefit - $2,340.00

Participation on this schedule is governed by the terms and conditions of
your Demand Bidding Program Contract.  Acceptance of any offers and
payment of any incentives for any accepted offers under this schedule is
subject to verification that you have not received any other incentive or
benefit from any sources for the same demand or load reduction included in
your offer and that you are not participating in any ISO ancillary service
or pay-for-performance program.

DON'T FORGET:  Your offer must be formally accepted by the California
Department of Water Resources (DWR).  Please ensure that you have received
confirmation from San Diego Gas & Electric that your pledged offer has
been accepted BEFORE you put your Demand Bidding Commitment into effect.

If you need assistance or have questions, please call              or send
e-mail to
```

DBP Participant Guide

STEP 11)
At or before 5 p.m. the day the bid has been submitted, you will receive a second e-mail indicating your pledge has either been Accepted or Rejected, in whole or in part.

When your bid has been accepted, you will be expected to reduce your load by the pledged amount during the pledged time block.

userjoe@hotmail.com

Save Address(es) | Block — **Previous** **Next** | **Close**

From :
To : <userjoe@hotmail.com>
Subject : (TESTING) Demand Bidding Summary For TEST ACCOUNT 1
Date : Fri, 12 Oct 2001 14:46:31 -0400

Reply | Reply All | Forward | Delete | Put in Folder... — **Printer Friendly Version**

```
Joe User,

Thank you for your participation in the Demand Bidding Program.

On behalf of the California Department of Water Resources (DWR), San Diego
Gas & Electric ACCEPTS and CONFIRMS the following Load Reduction Plan for
Test Account 1 - Test Facility 1 for Monday, October 15, 2001. Please
ensure that you reduce your load by these amounts for the time periods
indicated.

         Block A  8am-12pm 500kw    Reduction @ $0.300
         Block B  12pm-4pm 750kw    Reduction @ $0.500
         Block C  4pm-8pm  600kw    Reduction @ $0.100


If you need assistance or have any questions, please call              or
e-mail us at
```

DBP Participant Guide

DEMAND BIDDING SCREEN OPTIONS

The following Options are available from any screen within the Demand Bidding program:

Home — The **Home** button will bring you back to the main screen displaying all of your DBP participating "Site ID Descriptions."

History — The **History** button allows you to browse through bids for the most recent 30 days bids.

Help — The **Help** button provides on-line instructions and guidance on how to make a pledge. Use it as often as necessary.

Support — The **Support** button enables you to send an e-mail message to SDG&E, regarding the DBP program or any other SDG&E demand reduction programs.

Log Off — The **Log Off** button will end your bidding session.

D
ABBREVIATIONS AND ACRONYMS

These are a number of abbreviations and acronyms that are used in this document. Others might be encountered in discussing the issues associated with Demand Trading. In some cases, one or more letters may or may not be capitalized without changing the meaning (for example, Btu or btu).

AGA	American Gas Association
ALJ	administrative law judge; a hearing examiner within a regulatory agency
APPA	American Public Power Association
API	American Petroleum Institute
ATC	available transfer capability
Bcf	billion cubic feet
BPA	Bonneville Power Administration
Btu	British thermal unit; the heat required to raise 1 pound of water, 1 degree Fahrenheit
cfd	cubic feet/day
CFO	chief financial officer
CIO	chief information (IT) officer
C&I	commercial and industrial
CLEC	competitive local exchange carrier
CTC	competitive transition charge; used to recover costs stranded by customer freedom
DG	distributed generation
dkt	dekatherm; equals 1 mmbtu and is roughly equal to 1 Mcf

DOE	Department of Energy
DSM	demand-side management
DTT	Demand Trading Toolkit (this manual)
ECAR	East Central Area Reliability Council
EEI	Edison Electric Institute
ELCON	Electricity Consumers Resource Council
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas (but not all of Texas)
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
G&T	generation and transmission
GAPP	General Agreement on Parallel Paths
GRI	Gas Research Institute
GWh	Gigawatt hour; equals 1000 MWh
HVAC	heating, ventilating, and air conditioning
ILEC	incumbent local exchange carrier
INGAA	Interstate Natural Gas Association of America
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator

ISP	Internet service provider
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LADWP	Los Angeles Department of Water and Power
LDC	local gas distributing company
LSE	load-serving entity
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
Mcf	thousand cubic feet
mmbtu	million btu; generally equal to 1 Mcf
MW	megawatt; 1 MW = 1 million watts, enough power to supply 330 homes on a hot summer's afternoon
MWh	megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electricity Reliability Council
NOPR	notice of proposed rulemaking
NPCC	Northeast Power Coordinating Council
NRECA	National Rural Electric Cooperative Association
NYMEX	New York Mercantile Exchange
OASIS	open-access same-time information system
OMB	Office of Management and Budget; a federal bureau
PEM	proton exchange membrane (type of fuel cell)
PJM	Pennsylvania-New Jersey-Maryland ISO and reliability region

ppm, ppb	parts per million, parts per billion
PSC	Public Service Commission
PUC	Public Utilities Commission
PUHCA	Public Utilities Holding Company Act
PURPA	Public Utilities Regulatory Policy Act
PX	Power Exchange (California trading center)
QF	qualifying facility under PURPA
RBOC	regional Bell operating company
RFP	request for proposal
RTP	real-time pricing
RTO	regional transmission organization
SEC	Securities and Exchange Commission
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
T&D	transmission and distribution
Tcf	trillion cubic feet
therm	tenth of a mmbtu; 100,000 Btu
TURN	The Utility Reform Network; California ratepayer group
TVA	Tennessee Valley Authority
USDA	U.S. Department of Agriculture
WSCC	Western States Coordinating Council

Targets:

Determining System & Customer Opportunities

On-Demand Training for Using the Decision Framework and Program Design Tools

Preliminary Assessment of System and Customer Opportunities

Profiting from Excess Distribution Capacity

Customer Market Potential for Economic Development

Implementation and Evaluation of Economic Development/Electrotechnology Marketing

Overcoming Capacity Constraints

Customer Market Potential For Load Management/Energy Efficiency Programs

Implementation & Evaluation of Load Management/Energy Efficiency Programs

Demand Trading

Technical & Market Information Development for Demand Trading

Customer Market Potential for Demand Trading

Implementation & Evaluation of Demand Trading

Facilitating Customer Energy Management

Energy Management Technology Alternatives

Energy Management Services

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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