# 1. EMERGING ISSUES & BASIC CONCEPTS

## EMERGING ISSUES

### Rate Case Trends

Shareholder-owned electric utilities filed 66 general rate cases in 2009, the most of any single year in the past two decades. The main drivers of recently filed cases include utilities' infrastructure investments and capital expenditures, recovery of operating and maintenance costs, including fuel and other expenses, and efforts to establish tracking and adjustment mechanisms. The economic recession also has been a key driver in recently filed rate cases. Reduced customer usage, increases in uncollectibles, and cash flow and liquidity were among the economy-related issues cited in recently filed electric rate cases.

Despite the reduction in capital expenditure plans across much of the electric industry since late 2008, capital investments by utilities likely will remain at a high level well into the future since utilities increase earnings by growing the rate base with capital investments. Though reserve margins have increased in many power markets due to a decline in demand for electricity as a result of the economic recession, the longer-term need for investment in baseload generation will reappear as electric demand recovers along with the economy. Investment by utilities in transmission lines, renewable resources, and Smart Grid technologies is also expected to continue.

As electric demand recovers along with the economy, utilities' fuel and net power costs are also expected to increase.

It is difficult to read any publication or even newspaper articles on energy without seeing something about a Smart Grid and what it will do. Even politicians are getting into the act by promising monetary incentives for a Smart Grid. It is much harder to find a definition for a Smart Grid, but the basic concept seems to be a transmission system that not only flows electricity from the generator to the user, but will also flow information back and forth between the generators, the RTOs and the end-users. It will involve smart meters or, as it is sometimes called, advanced metering infrastructure (AMI). This information is supposed to enable all stakeholders – generators, suppliers, dispatchers, and end-users – to make more intelligent and, hence, more efficient decisions that will lower electric costs. Of course, all this new technology is expected to cost literally billions of dollars, and at this point it is difficult to predict how it will be paid for, who will pay for it, and whether it will produce the efficiencies to make it all economic. Industrial customers, of course, have engaged in this type of activity for years, using equipment and technology they paid for themselves. Consequently, the incremental benefit of wide scale employment of AMI is likely very small, or non-existent, for industrial customers.

## Demand-Side Management

Demand-Side Management (DSM) is a notion that has been discussed for the last twenty years or so, but has recently been put on the front burner by utility executives and regulators alike as the world has become increasingly environmentally-conscious. The basic concept is that a kilowatt or kilowatthour that is saved or avoided is the best way to curb emissions entailed in power generation. Prime examples of DSM are fluorescent lighting, high efficiency motors and appliances, greater insulation for homes and factories, and so forth. While everyone agrees that it is smart to use electricity in the most efficient and economical manner possible, the controversy is whether these measures should be left to the workings of a free market, or whether DSM needs to be fostered and administrated by a monopolistic and regulated utility. Those who are in favor of utilities employing and providing demand-side measures (as well as the traditional supply-side services) argue that “market imperfections” appear to make DSM less economic, relative to supply, than it really is. They point to "externalities" involved in generation that are not manifested in the actual price. These advocates also reason that the utility is in a better position to know the needs of their customers and to respond with DSM "solutions." Philosophically, these DSM advocates prefer central planning (or "Integrated Resource Planning" as the term is used in the electric industry) to relying on the free market.

Opponents of utility funded and sponsored DSM note that, unlike electric delivery service (and in most states generation too), DSM is not a natural monopoly, and that the free market is the best vehicle to allocate scarce resources. In other words, if DSM is really cheaper than supply, customers will choose to install these more efficient appliances themselves, without any assistance from the utility. They would also note that the utility might be conflicted since if the DSM measure does not save as much energy as advertised, the utility will be able to sell more electricity than it otherwise would. These opponents of utility-sponsored DSM also point to the increased overhead costs attendant to bureaucratic administrators. Moreover, if most of the funding comes from the utility, there is always the problem of free riders, those customers who would have installed (and paid for) the DSM measure on their own, but instead waited for the utility to subsidize the measure. In that case, the utility expenditure on DSM did not really serve its purpose because the measure would have been installed without the utility action.

When utilities do subsidize DSM, the controversy does not end. Obviously, the utilities wish to recover any DSM expenditures on their part, including any attendant overhead. In order to increase their cash flow, utilities prefer to expense the DSM funding in the year it is made, and recover the money contemporaneously from their customers. The counterargument is for the utility to rate base these expenditures and amortize them over the useful life of the measure, in much the same way that a utility treats supply-side measures. This usually results in lower rates. The major controversy, however, is how, and from whom, to recover these DSM-related costs. Unfortunately, all too often these costs are recovered from all customers on a uniform cents per kilowatthour basis. Not only does this method disadvantage large high load factor users of electricity, but it is not cost-based because it gives no heed to the DSM service received by the customer. Advocates of this socialization of DSM costs try to justify this treatment on the basis of a “System Benefits Charge,” arguing that DSM benefits everyone. Fortunately, industrial customers in some jurisdictions have been successful in either being able to opt out of the DSM program (and thus become exempt from DSM cost recovery), or to restructure the DSM cost recovery so that it is more proportionate to the amount of funds that are directed toward that particular class. In Montana, large customers are able to recoup any DSM payments to the extent that they have undertaken efficiency measures in their own plants.

Besides recovering DSM, some utilities also seek recovery of lost contribution to fixed costs. Their argument is that when customers reduce consumption in response to DSM, the utility still has fixed costs that do not go away. (Variable costs, by definition, will disappear in proportion to the reduced consumption.) Consequently, they seek to recover that contribution through a “Lost Revenue” rider. Otherwise, they claim that they will be penalized for pursuing DSM. Consumers, on the other hand, should strongly oppose such efforts. There are various reasons why “lost revenue” recovery is problematic, including the following:

(1) Other costs may have gone down or other revenues may have gone up, and so “lost revenues” is misleading.

(2) Utilities should not be *guaranteed* penny-for-penny recovery of costs, but rather only the *opportunity* to earn a fair return.

(3) The actual lost revenue due to DSM is exceedingly difficult to ascertain with any precision.

(4) Lost revenue recovery acts as a disincentive for customers to participate in DSM because their costs will go up if they do.

## Decoupling

"Revenue decoupling" is another twist to the lost revenue arguments. The underlying concept is very similar; that is, to ensure that the utility is held harmless by a reduction in sales. Decoupling refers to disassociating the revenue that the utility receives from the actual level of sales. This means that as sales (of kilowatthours or kilowatts) decrease, the rates go up inversely proportional to the decrease in sales, so that revenues remain constant. Decoupling can be affected on a class level or on an individual customer level. In either case, you should be aware that decoupling transfers risk from the utility to the customers. As with lost revenue mechanisms, it also diminishes the incentive for customers to reduce consumption.

## Climate Change/Greenhouse Gas Emissions/Renewable Portfolio Standards

No list of emerging issues in the electric industry would be complete without mentioning climate change. As society is becoming increasingly cognizant of the perceived consequences of climate change or global warming, and as scientists point to the culprit as greenhouse gases and the danger of other emissions such as $NO_x$ and $SO_x$, the term "Externalities" crops up more and more in White Papers, Legislative initiatives, and even regulatory Decisions. Externalities are those environmental and social costs or benefits of energy which result from the production, delivery, or reduction in use through efficiency improvements and which are external to the transaction between the supplier (including the supplier of efficiency improvements) and the wholesale (e.g., utility) or retail (e.g., ratepayer) customer. Externalities may be quantified and expressed in monetary terms where possible. Governmental agencies, and legislatures, and regulators are becoming concerned that because externalities are – by definition – not reflected in the ratemaking process, utilities and consumers are not sending or receiving (or perceiving) the appropriate price signal and, therefore, are making (or not making) the most appropriate decisions as it affects the environment.

To remedy this ostensible flaw in the market, federal and state legislators are proposing new rules and regulations intended to induce what they consider more appropriate behavior. This has led to new mechanisms and concepts such as Renewable Energy Credits, Renewable Portfolio Standards (RPS), and the Regional Greenhouse Gas Initiative in the Northeast. These mechanisms either mandate a minimum amount of energy that comes from renewable resources, as opposed to fossil fuels, or require certificates or allowances that work to limit the amount of emissions that are considered harmful. The certificates evidence compliance with these legislatively set targets and are tradable. They are intended to allow parties that value them the most to pay the appropriate amount for them. In other words, all these mechanisms are an attempt to let the market monetize the cost of these externalities. For the end-user, it means that the cost of electric power is going to increase over the foreseeable future, all other things being equal.

There also has been significant attention lately on the government's efforts to establish a cap-and-trade mechanism in order to reduce greenhouse gas (GHG) emissions. Much of this focus has been on the broad economic impact that would result from setting a price on the right to emit GHGs. There is certainly no consensus yet regarding how any eventual regulation will be implemented. Though much of the burden associated with GHG regulation would fall on electricity generators, many generation owners in integrated utilities support a cap-and-trade regime. In regulated markets, generation owners would have the opportunity to fully recover these compliance costs in the form of higher rates. In deregulated markets, generators would recover the compliance costs through higher offer prices in spot and forward power markets. The market clearing price would likely increase to recover the compliance cost. As a result, low-carbon generation sources such as nuclear would benefit by higher market prices and would likely recover revenues well in excess of their cost of compliance. In either case, the cost of compliance ultimately would be borne by the consumer.

## Interruptible Credits

A growing trend observed among some electric utilities is to under-value the credit paid to industrial customers for interruptible load, particularly in the recent temporary economic recession, where electrical supply is outstripping demand. This electric supply situation has caused the market price for electricity to decline. Rather than valuing interruptible load on the basis of the utilities' long-term avoided costs to serve firm customers, including the costs associated with the construction and/or purchase of long-term firm capacity resources, some utilities are attempting to value interruptible loads on the short-term avoided costs of market purchases. While this approach may be appropriate in some circumstances, it generally undervalues the interruptible load of customers who are willing to commit to interrupt and, therefore, results in the customer paying a rate higher than what is reasonable. A short-term valuation does not properly reflect the capacity value of interruptible load. The capacity value implicit in current electric market pricing is typically below the capacity value of the long-term resources constructed or purchased by the utility to serve firm load.

By proposing a short-term valuation for interruptible load, utilities are effectively arguing that while rates to serve firm customers are increasing due to the construction and purchase of firm capacity resources, the value of interruptible load has decreased. This argument is both counter-intuitive and incorrect. Though wholesale market prices for electricity have plummeted since mid-2008, triggered by a drop in electrical demand (primarily industrial load) and the market price of oil and natural gas, economic theory tells us that this current remission – brought on by the current state of the economy -- will only be temporary. Natural gas and electricity prices will rebound as demand for these products eventually recovers. In addition, over time, in order to sustain the market, the market price for electricity will need to rise to the levels necessary to support the all-in cost of the least cost source of electric supply that is readily available.

What is an appropriate valuation of industrial customer interruptible load that is committable to an electric utility on an extended term basis? One reasonable approach to valuation is to use the cost of a combustion turbine peaking unit. This is reasonable because this type of generation generally has the lowest installed cost of the generation capacity that is widely available. This approach is used by electric utilities located in many different jurisdictions. Recent cost estimates for the value of new combustion turbine capacity range from around $6 to $12 per kW-month. When valuing interruptible load in this way, electric utilities should properly account for all factors that affect the value of the interruptible resource relative to the value of the new combustion turbine. For example, reduction in transmission losses and generation planning reserves should be taken into account. These factors directly favor demand response resources such as interruptible load over generation resources. In addition, other less direct factors should be considered.

## Riders/Automatic Price Adjustment Clauses

It is important for customers to understand the difference between base rates and riders or trackers. Base rates are established in a general rate proceeding. They are based upon a snapshot of all the utility's revenues, expenses and investments for a given period. Riders, on the other hand, are designed to track changes in only a single cost item. For example, the most frequently encountered trackers or riders are automatic fuel and purchased power adjustment mechanisms. However, it is becoming more common to see riders used to recover DSM costs and/or lost revenues. Typically, riders are intended for cost items that are significant and volatile, and considered to be outside of the utility's control. However, riders are frequently misused. The advantage of a rider is that it exactly matches the cost with the revenue for the covered items. Riders can also reduce the need for frequent rate cases. The disadvantage of a rider, however, is that it constitutes single-issue ratemaking. A rider can increase utilities' revenues, even when its overall costs are going down or its revenues are going up. Furthermore, because riders are automatic, they provide no incentive for the utility to control the particular cost in question. As the financial world has become more averse to risk taking, utilities are turning more and more to new riders in an attempt to shift risk from the shareholders to customers. Unfortunately, regulators are all too often amenable to granting these riders, but without making compensating adjustments in the utility's authorized return on equity.

## Nuclear Generation

There are 104 nuclear reactors in the U.S. that generate electric power. Nuclear power accounted for 20% of total U.S. electric generation production in 2009. In 2009, the average cost to produce electricity from nuclear power was $18 per megawatthour ($/MWh) – $5 for fuel and $13 for non-fuel O&M – compared to $29/MWh for coal, $46/MWh for natural gas and $110/MWh for oil. Typically, nuclear fuel accounts for only 25-30% of total nuclear power production costs, compared to 80-95% for coal, oil and natural gas generation.

Though nuclear generation has lower production costs on a $/MWh basis as compared to other types of generation, nuclear generation has much higher capital costs. An optimistic estimate of the all-in cost of nuclear generation (production + capital) is approximately $100/MWh as compared to $80/MWh for coal generation and $70/MWh for combined cycle natural gas generation. The actual all-in cost of nuclear generation could be much higher.

Despite the high all-in cost of nuclear generation, a renewed interest in nuclear energy is occurring in the U.S. and worldwide. This interest is driven by the low and stable production cost of nuclear-fueled generation, the security of uranium fuel supply and environmental considerations. However, new nuclear plant development in the U.S. is unlikely to occur rapidly.

Builders of new nuclear plants must contend with a potentially slow regulatory and licensing process. High construction costs make it very difficult for nuclear plants to be developed by electric utilities in the absence of federal loan guarantees. Obtaining financing to build capital-intensive nuclear generation projects will be a challenge for electric utilities. The vast majority of electric utilities in the U.S. have indicated that without federal incentives for nuclear generation, building a new nuclear plant will not be economically feasible. The capital intensive nature of nuclear generation construction and its associated financing challenges has caused utilities in some states (e.g., North Carolina, South Carolina, and Iowa) to seek legislation to recover the costs of construction work in progress (CWIP) related to nuclear power from ratepayers prior to the nuclear plants being placed in service. Utilities seek CWIP in order to limit their risk associated with nuclear power plant construction.

Despite nuclear power's generation cost and environmental advantages, the future of nuclear power in the U.S. will be shaped in part by the strategy for long-term storage of spent nuclear fuel. Until recently, Yucca Mountain in Nevada was the chosen location for a national repository for spent nuclear fuel. However, the Obama Administration has rejected this as an option for storage, and is currently considering new strategies for disposal of radioactive waste from nuclear generating facilities.

Recently there has been much focus on Small Modular Reactors (SMR) as possibly the next generation of nuclear power plants to be constructed in the U.S. SMRs will be relatively small in power output (25 MW to 350 MW) as compared to large-scale reactors that can have a power output of more than 1,200 MW. Unlike traditional large-scale reactors currently operating in the U.S., SMRs would be manufactured and assembled at the factory and shipped to the utilities' sites as nearly complete generating units. SMRs would allow more flexibility than large-scale nuclear reactors through smaller, incremental additions to baseload electrical generation. SMRs could be added and linked together for additional electrical power output as needed by an electric utility. SMRs will be new in design, siting, construction, operation and decommissioning as compared to current large-scale reactors operating in the U.S.

# BASIC CONCEPTS

The purpose of this section is to provide the reader with an understanding of the basic economic and engineering concepts that are fundamental to an understanding of your electric bill and to alert you to emerging issues that will shape the electric industry and potentially have huge consequences on your cost of power.

Most people think of electricity as a single service but, in actuality, electric companies perform several clearly distinct and identifiable functions. Those functions are generation, transmission, distribution and customer-related functions, such as metering. It is also important to understand that the cost drivers of these functions are: (1) annual energy usage by the customer; (2) peak demand imposed on the system by the customer; and (3) the size or number of customers attached to the system. In this section, we will also learn that there are different types or measures of demand. The key metrics, which impact your cost of electricity – load factor, coincidence factor, capacity factor and power factor – are explained in this section.

The electric industry can be subdivided into several distinct functions. The first function, and the one that accounts for most of the cost, is the generation section. This is where the electricity is actually produced. These are typically large power plants (sometimes referred to as generation stations) that are centrally located. Then, of course, we need the means to deliver or transmit this power from the generating station to the customer. Normally, the electricity is stepped up to a very high voltage for efficiency reasons and transmitted long distances over transmission towers and wires. Then, it is stepped down to lower voltages as it gets closer to the customer's location.

The lower voltage system is termed the distribution system and can further be distinguished as primary (typically voltages of 4 kV to 13 kV) or secondary. Note that customers served at higher voltages do not need or use (and so should not pay for) the lower voltage facilities. Finally, the power is delivered through the meter to the customer.

Typically, all of these functions are provided by a single, vertically integrated utility. However, in recent times, several utilities have nominally, and sometimes physically, disaggregated into distinct companies, each of which provide just a single service or function. Some companies have decided to concentrate their efforts in the generation section. Others have decided to take a less risky route and have been called wires companies because their sole job is to deliver electricity from the generator to the customer.

It is important to note that customer choice really revolves around the generation function of the electric industry; whereas, the wires portion still remains, and will continue to remain, a monopoly service. There may also be some competition in the customer service end, such as metering and billing, although it is far less common.

Most utility costs can be classified according to what aspect of the customer service is driving these costs. Energy costs are driven solely or predominantly by the amount of energy that is consumed, regardless of how fast it is consumed. In other words, energy costs are directly proportional to the amount of the energy the consumer uses. (Although energy costs are sometimes subdivided according to the time of day or season when the energy is consumed.) The prototypical energy-related cost is fuel. The amount of fuel that a utility consumes is driven by the amount of energy it must provide. On the other hand, other costs are driven by the rate at which the energy is consumed. The term for the rate at which energy is consumed is called demand and is measured in kilowatts or megawatts. Because electricity cannot be stored, the utility must build its generating plants and its wires to have enough capacity to accommodate the peak demand that is placed on the system at any point in time. Finally, there are costs such as metering costs and billing costs that really relate only to the number of customers on the system, sometimes their size as well, but do not vary at all with either the amount of energy or the demand placed on them.

One cannot overemphasize the importance of distinguishing between energy and demand. Energy is measured in kilowatthours; demand is measured in kilowatts. So, if five 100-watt bulbs burn for two hours, the energy consumed is one kilowatthour during that period (500 x 2 = 1,000 watt-hours or 1 kilowatthour). The peak demand placed on the utility is 500 watts. On the other hand, if two 100-watt bulbs burn for five hours, usage would also be 1,000 watt-hours or 1 kilowatthour. However, the peak demand that this customer is placing on the system is only 200 watts.

**Slide 29** shows in a graphic pattern the load shape that occurs in these two instances. Notice that the shaded area in both cases is exactly the same. That is because both customers have used one kilowatthour of energy. However, note that the shaded area is much taller for the first instance than the second. That is because the first customer is imposing a much higher demand on the utility. Consequently, it is much more costly to serve the first configuration than the second because even though they both use the same amount of energy, the former is imposing two and one-half times the demand of the latter.

Load factor is a metric used to measure how efficiently a customer is utilizing its capacity. A customer that utilizes demand relatively constantly is said to have a high load factor. On the other hand, customers that use their electricity sporadically, have a low load factor. This distinction is important because while energy costs are variable, demand-related costs are fixed. A high load factor customer is taking those fixed costs and spreading them over a much larger energy base. Consequently, a high load factor customer should impose a lower cost per kWh than the low load factor customer and should be charged a lower cost per kWh then the low load factor customer. Just as a customer who rents a car for one day and travels 1,000 miles will have a lower fixed cost per mile than a customer who rents the car for a day but only travels 100 miles. Load factor is defined as the ratio of a customer's average demand to its peak demand.

In general, a customer can improve its load factor in one of two ways. It can use more energy to keep its demand at a constant level, or it can use the same energy but reduce its peak demand. Utilities generally like to encourage high load factors because it imposes less cost on the system.

There are two measurements of a customer's demand that are relevant to the cost that the customer imposes on the system. The first measurement is the coincident peak. This is the measurement of the customer's demand at the time the system peaks. The second measure is called the non-coincident demand. This is the customer's maximum demand regardless of the time when the customer might peak. For example, if the system peaks on August 15 at 3:00 o'clock in the afternoon, then it is only the customer's demand in that hour that contributes to the utility's coincident demand. Why are these two different types of demand important? They are important because different parts of the utility system must be based on different types of demand. Facilities that serve a very large number of customers (such as a generating plant) must be built with the idea of satisfying the coincident demand, regardless of when the individual customers peak. On the other hand, a line transformer that is sitting outside an industrial plant must be sized to meet the size of that industrial plant regardless of when it peaks. Therefore, some parts of the utility system are built with the coincident peak of the system in mind; whereas, other parts of the system must be designed to accommodate the individual demands of the customer.

**Slide 35** shows the demand of two classes of customers – A and B – over a period of time. The top curve, the coincident peak, is the sum of the curves of Customers A and B. Notice that the coincident peak occurs at a time that neither Customer A or B is peaking. Notice also that the coincident peak of a customer or a class is always less than its non-coincident peak. The relationship between the coincident peak of a class and its non-coincidence peak is called the coincidence factor. The higher coincidence factor, the more a customer is contributing to the peak of the system in relation to its individual peak. In the following table Customers A and B both have the same non-coincident peak, but Customer A has a coincidence factor of 80% and Customer B has a coincidence factor of only 20%.

**Illustration of Coincidence Factor**

| | Coincident Demand | Non-Coincident Demand | Coincidence Factor |
|---|---|---|---|
| Customer A | 80 | 100 | 80% |
| Customer B | 20 | 100 | 20% |

Therefore, Customer A is imposing four times as much demand on the system at the time the system is stressed as Customer B is. The reverse of coincidence factor is termed diversity factor.

Like load factor and coincidence factor, power factor is another metric that determines the cost a customer imposes on the utility. Many utility companies charge you an additional fee if your power factor is less than 0.95. Lower power factor also reduces your electric system's distribution capacity by increasing current flow and causing voltage drops.