IssuesLetter

Stranded Costs
and Other Risks to Look Out For

Today's regulators, in response to calls for increased competition from the electric utility industry, face a very full plate of new issues. Figuring out what kind of competition makes sense and how to get there is an enormous challenge. Often, the debate is over whether retail competition, that is allowing customers to shop for generation, provides any advantage over wholesale competition among generators. But there is a more basic question which needs to be answered first.

At the heart of nearly any competitive option is the problem of stranded costs. In general terms, stranded costs represent the difference between today's retail electricity prices and the current market price for power -- a difference that today is very large. What stranded costs are and how they should be handled lie at the center of any discussion of restructuring the electric industry.

This Issuesletter defines and describes, at least conceptually, how to measure stranded cost; illustrates that disposition of stranded cost is at the core of every response to competition, including retail wheeling, flexible pricing and special contracts; and discusses the risk allocation implications of each of these responses.

What Are Stranded Costs?

The primary concern at this time is not about costs that have been stranded but about costs that are at risk of becoming stranded in the future. Therefore, the term strandable, as opposed to stranded, better describes this issue. With a few exceptions, nearly all of these costs are currently in rates. Whether or not a strandable cost actually becomes stranded depends on actions that utilities, customers and regulators take. Many of the issues before regulators today involve decisions that may create stranded costs. It is only in cases where stranded costs are created that regulators must decide what they are and who pays. The shareholders? The customers? Which customers?

Breaking down the definition of strandable costs makes the concept easier to grasp.

Step 1

By defining strandable costs as the maximum amount of money that the utility is now collecting that is at risk, they can be calculated quite simply as the difference between what the utility now charges a customer minus any cost it avoids if the customer is no longer served.

Example 1: Assume an industrial customer now pays the utility $1 million per year for service. If the customer moves the factory to another state, the utility's annual revenues go down by $1 million. But the utility's costs also go down. Assuming fuel savings reduce the utility's costs by $600,000, $400,000 per year would be left stranded. It will be up to regulators to decide how these costs should be recovered.

Step 2

Suppose the customer does not move the factory but instead takes advantage of retail wheeling and chooses a different supplier. Because the customer continues to be connected to the utility, she will continue to pay some reasonable charge to use the local utility's transmission and distribution system. Now the strandable costs are the difference between what the utility currently charges a customer minus any cost it avoids if the customer is no longer served minus any charges for residual services, such as transmission and distribution.

Example 2: If the same customer leaves the utility through retail wheeling and pays the utility $100,000 per year for transmission and distribution, the strandable cost drops to $300,000. (The original $1 million less the combination of fuel savings and transmission and distribution services.) Regulators will be asked to decide who will pay for these costs in the future.

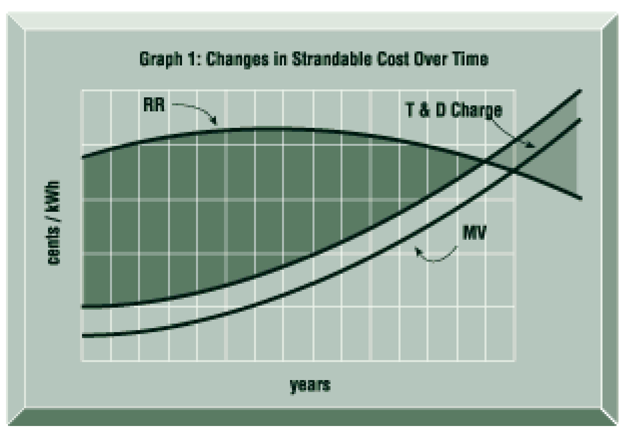
Step 3

The element of time, unfortunately, makes the second definition incomplete. The definition is correct and reasonably accurate for the first year. But what about years two, three...? Adding the element of time not only leads to the full definition of strandable costs, but it also exposes its most difficult issues. These are the uncertainties of calculating the number and the risks of getting the number wrong. By taking the time element into consideration, this third definition defines strandable cost as the present value of the difference between what the utility would have charged the customer over time minus any cost it avoids over time if the customer is no longer served (this is also the market value of power over the same time period) minus any ongoing utility charges for residual services.

Example 3: The customer is a retail wheeling customer now and for the next 20 years. By using the equation from example 2, a yearly stranded cost determination can be made. The shaded area of the graph 1 below shows these year by year stranded costs, both positive and negative.

An examination of what the lines represents illustrates the complexity of calculating stranded costs over a number of years.

Graph 1



Revenue Requirements (RR)

The most familiar part of the graph, the line labeled RR, is the revenue requirements per kWh. This line, as will be seen in subsequent graphs, is the same as the average retail rate.Two issues arise when estimating this line into the future.

1. Forecasting load, fuel costs, interest rates, inflation and all of the other parts of the revenue requirement is inherently risky. Even the best crystal balls are never perfect.

2. Forecasted revenue requirements means estimating costs associated with today's service that are not yet in rates. Examples include the future costs of existing power purchase commitments, deferred costs of all sorts, the costs of unfunded nuclear decommissioning, waste storage and

salvage value of plants and sites. If today's customers remain with the utility, they would be expected to share these costs and revenues at a later date. By leaving, their share of these unknown costs and revenues are strandable.

Market Value (MV)

The line labeled MV looks familiar because it has the same shape and level as avoided cost projections. This is not a coincidence. For all practical purposes, market value and avoided cost are the same. However, while these terms can be used synonymously, market value has a very different use than avoided cost. It is this use that makes the task of determining market value and the consequences of getting it wrong much more daunting.

1. Avoided cost is typically used to place a value on small additions to the existing generation system. For many policy choices now under consideration, market value for estimating strandable costs, sets a value for the entire system -- both existing and new generation. If the avoided cost for a 50 MW resource addition is off by $1/KW, the mistake will be a contained one. But when calculating strandable costs, the impact of the same error, because it applies to the entire system, will be much, much greater.

2. With avoided costs, it is possible to limit consideration to resource options within the utility's control. Market value calculations, on the other hand, require forecasting a value for generation in the context of a much larger, deregulated regional market. If the market mechanisms needed for a regional generation marketplace existed, (power pools, open access transmission and structural reforms that eliminate affiliated transactions or market power), these forecasts would be difficult enough. However, since these market mechanisms do not exist, market value forecasts are made with very limited information and understanding.

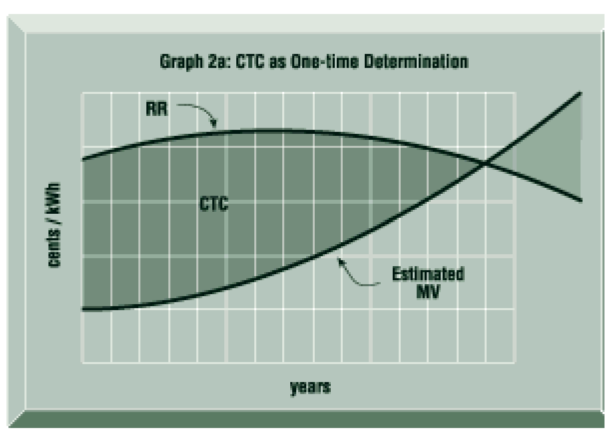
Stranded Cost (SC)

The California PUC's first attempt at defining stranded cost reveals the enormity of the risks associated with the policy options under consideration. In its original vision (the "Bluebook"), the California Commission proposed a policy course which included identification of strandable cost as a first step in deregulating generation and giving all customers direct access to generation priced at market value. To do this, they proposed a regulatory proceeding that would quantify stranded costs and allow utilities to recover that amount through competition transition charges (CTC). The CTC is calculated based on the commission's best estimate of stranded cost (the shaded area), including its estimate of the market value of generation resources.

Consider what happens if the actual market value -- the price customers pay for electricity -- turns out to be different than the commission's original estimate. The following sequence of graphs shows what can happen.

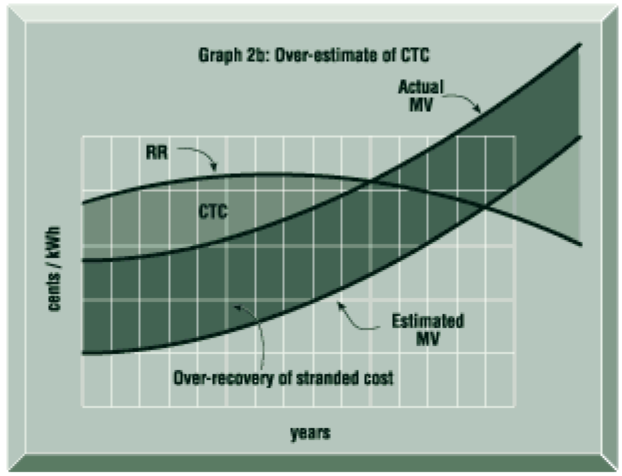
The first graph, 2a, shows the CTC as a one-time determination.

Graph 2a



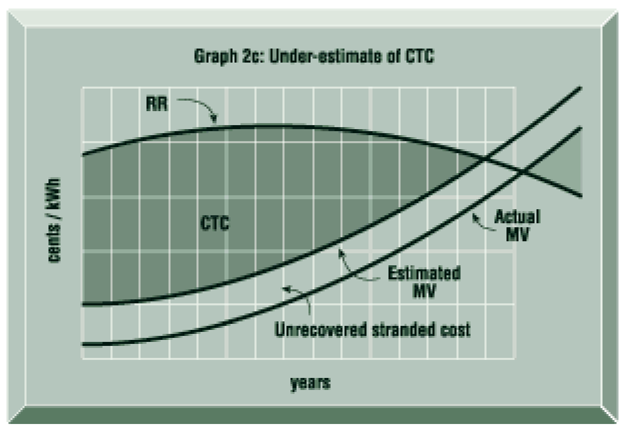
Graph 2b shows what happens if, after the CTC is determined, gas prices rise higher than expected. Market value rises significantly, revenue requirement (that is the gas-fired portion of the utility's fuel mix) rises very modestly and stranded costs are essentially eliminated. (Note that for the purpose of clarity, this illustration shows an unchanged RR line.) But under California's original vision, the original CTC remains, and the customer pays the higher market price. In other words, customers pay the double-shaded area twice, first in the CTC, then in their power purchase.

Graph 2b



Graph 2c shows what happens if gas prices fall below forecasts. Customers pay a low market price for generation and a CTC that leaves some stranded costs uncovered.

Graph 2c



Points Not To Forget

The examples above illustrate two fundamental points. The first is that because there is a great deal of uncertainty surrounding strandable cost determination, even the best and most unbiased attempts will produce a number that will be wrong. What is not known is by how much and in what direction the error will fall. (For a medium to large electric utility, errors of several $100 million are possible.) Second, how customers, shareholders and utilities are exposed to the consequences of errors in stranded cost determination depends entirely on the form, pace and scope of policy choices made by regulators.

Policy Responses to Competition

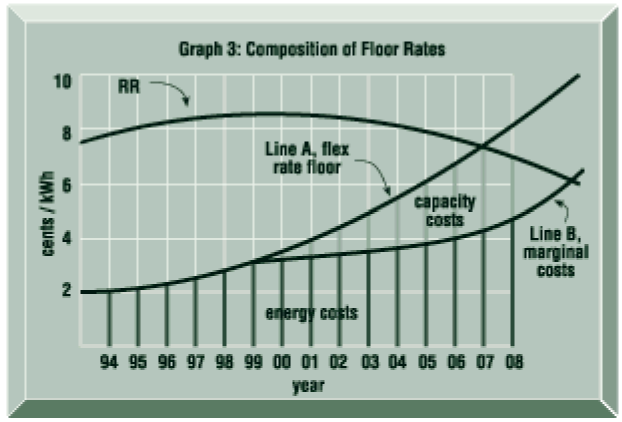
Regulators are considering a wide choice of policy responses to increased competition. This section looks at two frequently considered responses and evaluates what competitive benefit they offer, how they handle strandable costs and how risks are affected.

"Flex" Rates and Rate Design Solutions

With increasing frequency, commissions are being asked to approve special rate discounts (sometimes called economic development rates) for large industrial customers to attract new customers, encourage expansion or to retain customers who threaten to close their plant, move it to a different service area or self-generate. In theory, discounted rates, load retention and cogeneration deferral rates aim at setting rates that cover short run fuel costs, plus some contribution to fixed cost. While hypothetically this pricing is competitive and contributes to fixed costs, in reality, pricing on this basis may yield prices lower than what competitive markets would charge and in doing so exacerbate, not improve, stranded cost recovery.

Graph 3 illustrates why the stranded cost problem can be aggravated with flex rates that assume a short run marginal cost price floor.

Graph 3



Here, a marginal cost line replaces the market value line. The area under the line is further divided to show the portion of marginal costs that covers fuel and the portion that covers future capacity costs. (For the sake of simplicity, all the area shown as capacity is the annual capital cost of a new baseload plant added in 2000). The line labeled A represents the price the customer would pay if she were to make no contribution to stranded cost. Any rate set below line A increases stranded costs because the utility (or other customers) must absorb the added capacity costs.

Flex rate contracts typically run for short periods of time -- one to three years. Graph 3 shows that from 1994 to 1999, the flex rate floor (line A) is the same as the marginal cost. However, during this period planning and investment decisions are typically made under the assumption that the utility will continue to serve the customer well into the future. In this case, new capacity is added in 2000.

In 2001, the customer may again seek a special deal based on the same economic principles applied in 1994. However, the new plant, together with its capital costs (sunk as of 2000), have changed the economic picture. Now, line B reflects the marginal energy costs (including the fuel for the new plant). If the customer is allowed to pay only the energy costs, the cost of adding capacity is borne by shareholders or other customers. As the graph shows, charging prices that follow line B rather than line A increases the stranded costs. Not charging for capacity additions also raises doubts about any assertion that flex rate policies are consistent with competitive pricing.

If, despite these issues, commissions decide to grant flex rates, these rates must, at a minimum, recover marginal fuel costs, capacity investments and transmission and distribution charges and should include as much of the strandable cost as possible. In addition, contract terms should specifically notify customers that either no capacity additions are being planned for them, thereby making them responsible for the full incremental costs of service in the future or that capacity additions are being planned, and that they are responsible for covering the costs in the future.

Either of these protective measures will work in theory. Both, however, rely on ongoing enforcement which will vary from state to state and from time to time.

Retail Wheeling

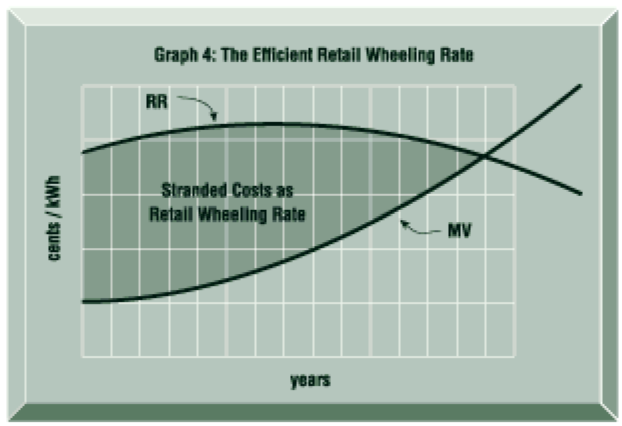
Another policy option commissions face is retail wheeling. Under this scenario, a utility's generation, transmission and distribution services are unbundled. Customers shop for their own generation and pay a wheeling rate for use of the wires. This option, if implemented and structured correctly, has the ability to offer both competitive benefits and recover stranded costs. Its success hinges on setting the right retail wheeling rate (RWR).

Graph 1 illustrated the relationship between stranded cost and a retail wheeling (or T&D) rate. In that example, the RWR was shown as the transmission and distribution charge at an arbitrary rate of 1/kWh, an assumption we now revisit As already discussed, the revenue requirement and market value lines are quite uncertain. While regulators may be called upon to forecast what these lines look like, they have no meaningful ability to control their actual values. For all practical purposes then, these two determinants are uncontrollable by regulators. The third factor, however, the wheeling rate, is completely controllable. The RWR results in no stranded costs when calculated as the retail rate minus the avoided cost:

RWR = RR - MV

Graph 4 shows how this equation results in no stranded costs.

Graph 4



This determination also supports economic efficiency. The argument for retail access is that it gives customers an opportunity to lower overall costs. This occurs when customers are able to acquire resources at a cheaper price than the utility. The RWR calculation gives customers economic price signals to do just that.

For example, assume a retail rate of 5 and the utility's avoided or marginal cost of serving the customer is 2. If the customer chooses a 3 alternative supplier, the decision is uneconomic. Using flex rates, the ordinary response would be to lower the 5 rate to somewhere between 2-3 so the customer will decide against the uneconomic, 3 option. In the context of retail wheeling, the RWR provides the tool to produce the same result. A 3 RWR rate discourages the customer from selecting the 3 option but encourages her to beat the 2 marginal cost of the utility.

Some Stranded Costs Can Still Be Apportioned to the Utility

Setting a RWR does not preclude a commission from asking utilities to assume some of their strandable costs. What it does prevent is having utilities or other customers absorb only those stranded costs from customers who leave. If a regulator wants a utility to write off a portion of the stranded costs, it should be done as a principled policy decision that lowers the retail rates of all customers. The RWR would then be calculated after such a decision is made.

Parting Thoughts

This Issuesletter looks at only two policy responses to competition currently before commissions. Unless done properly, these approaches carry not only the risk of shifting costs and allowing consumers to make uneconomic decisions but also the risk of stranding benefits, such as environmental protection, energy efficiency and long term planning by utilities. While estimates of the dollars at risk from stranded costs vary, it is clear that a swift move from existing revenue requirements to the current depressed market prices would severely injure many (perhaps most) utilities and could bankrupt some.

There is, however, widespread recognition that fully competitive markets for electricity generation are desirable. There are two directions utilities and regulators might take, each of which has its drawbacks. The first waits for stranded costs to disappear as existing high cost utility plants depreciate, power purchase contracts lapse and excess capacity is utilized. There is a good chance that during this time, market prices will rise as supply and demand for generation move into balance. This wait-it-out strategy is embraced by many utilities and is a driving force behind special rate deals, but if it works at all, it will work slowly.

Shoppers Tariff To Calculate Ongoing Market Value

The Shoppers Tariff calculates a market value for power on a monthly basis. Using this system, a customer getting electricity from another supplier receives a monthly bill from her original local utility as if the utility was continuing to provide her all services. However, subtracted from the bill is a rebate representing the amount the utility saves (administration, fuel and any incremental generation costs) by not having to provide power to the customer. The customer uses this credit to shop around for an alternative (and hopefully cheaper) source of power. Rebating the customer only the amount saved by not having to serve her, means that there is no shifting of costs onto the remaining customers.

The other choice is to seek mechanisms to deal directly with stranded costs while simultaneously restructuring the industry and its regulation. Indeed, while many see stranded costs as the primary obstacle to competitive generation, others see it as the critical and, until now, lacking leverage to move toward increased competition. Getting competitive generation is not easy and will require industry restructuring in ways that regulators cannot impose against the will of utility managers. Because stranded costs come under regulatory control, dealing with them may provide the needed catalyst for productive change.

Flex Rate Minefields

Are they legal?

Commissions are expected to set non-discriminatory rates. Discounting rates for a few customers may discriminate against customers who did not receive a special deal, particularly those who compete with the customer receiving the discount.

Who knows if claims are legitimate?

While there is every incentive for a customer to argue hard for a discount (and even bluff), commissions typically lack detailed knowledge about the customer's business because customers are reluctant to fully divulge sensitive information to commissions. Imposing revenue losses resulting from discounts onto the utility is the main tool used by regulators to transfer the burden of proof from the regulators to the utilities. This move also gives the utility an incentive to offer as small a discount as possible.

While in theory this is a logical step, there are two reasons to be skeptical about this solution. First, this is an easy policy to implement when discounts are awarded between rate cases, but it is very difficult, if not impossible, to assure that revenue loss will continue to be allocated to shareholders once the utility files its next case. Second, if the utility is (or would otherwise be) overearning, requiring shareholders to absorb these revenue losses merely takes what would be a rate reduction for all customers and allocates it to a small class of customers. This means that adopting special rates on a case-by-case basis will result in inconsistencies with rate design.

The consequences of mistakenly granting a deal are small.

Refusing to approve special deals is risky for commissions. If they wrongly deny a flex rate and a large employer leaves the state, they may be blamed. Conversely, if they mistakenly approve a deal, the error will never surface. Granting the special contract is even easier if regulators believe utility shareholders will pay the revenue loss. But as described above, this may be a easier said than done.

Rate discounts offered to one customer will be sought by others.

Once commissions say yes to one customer, they might find themselves on a slippery slope where it gets increasingly difficult to say no to subsequent requests.

What is the net impact on jobs?

If flex rates result in raising the rates of other customers, those customers will become less competitive. The number of jobs created (or maintained) by offering a low rate to one customer may be offset by jobs lost from other customers who are paying more.

Flex rates are anti-competitive.

Special rates are potentially both discriminatory and anti-competitive. By offering uneconomically low rates to customers with legitimate competitive alternatives a utility squeezes out competition. This is never desirable, particularly if other customers are subsidizing the discount.

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