

How Can Consumer Advocates Deal with Soaring Energy Prices?

A Re-Restructuring Menu

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Gerald Norlander

Public Utility Law Project of New York, Inc.

A number of major problems are now confronting states that restructured their electricity systems.

The restructured systems have not reduced overall demand for electricity or fostered development of sufficient new power plants or transmission to meet demand. Demand is growing and generation adequacy and reliability are imperiled in some areas. Generation owners effectively have the option of choosing the higher of cost based or market based rates in constrained areas.

Market-based solutions to increase generation supply to meet reliability or price concerns involve paying existing owners of generating plants large capacity payments in the hope that this will induce them - or others - to build new power plants, without any assurance that new plants will actually be built. Merger activity in the generation sector is raising new market power concerns.

If new plants are built or if demand is reduced, merchant power plant owners may retire existing plants ahead of schedule, thus perpetuating shortage and opportunities for scarcity pricing.

Rates for electricity in the restructured states are essentially linked to natural gas prices, due to the impact of uniform clearing price spot markets that pay low cost generators the same price as the highest cost generator running, which is typically fired by natural gas. Increases in natural gas costs thus raise wholesale rates for all generation regardless of fuel type.

As retail price caps come off, and as long term wholesale contracts which made the price cap rates possible expire, retail customers are facing much higher prices based on wholesale market rates.

Following are a few ideas for a "re-restructuring" menu.

1. Re-Verticalize Utilities to Regain State Control of Generation Costs. A state might reassert cost of service regulation over generation by re-verticalizing retail distribution utilities. To the extent that lower cost generation can be gotten back into a vertically integrated structure, customers would get the electricity based on its cost of production.

When the plants are owned by a vertically integrated utility - which is the case in most states - the state regulator sets rates based on the cost of service. Then, the production cost, plus a return on equity invested by the utility in the power plant asset is all the utility gets for the energy. The value of fuel diversity and lower cost generation goes to the consumer. Of course, this is a two way street, if the utility owned power plant turns out to be high cost.

When utilities "restructured" they divested their power plants to new owners who now have wholesale "market rate authority" from FERC. This may be over compensating low operating cost generation (typically hydro, nuclear, and coal) and possibly under compensating some peaker units (if they bid their output to recover only their running costs and not their capital costs). The benefit of fuel diversity and low cost production tends to benefit the producer rather than the consumer.

If it may be easier to take power plants back into a vertically integrated state regulated structure if they were divested to a subsidiary or holding company affiliate of the distribution utility. Even if the plant is now much more valuable as a merchant power plant than it was previously as part of a vertically integrated utility, it could be argued that a utility that sold an asset to a holding company affiliate cannot later buy it back at a higher price, taking an unregulated profit on the markup through the sale and buy-back transaction with the affiliate.

If the power plants were highly valued when sold to unaffiliated owners, or, if after divestiture the plants were resold ("flipped") at a much higher price to another set of owners who anticipated the bounty of market rates when they bought them, the price of re-acquiring the plant could be much higher than the depreciated book value of the plant when it was owned by the utility.

Some of the divested plants were old, inefficient, and major polluters. These plants might not be worth re-acquiring.

If cost effective wind or hydro power is built or bought by the re-verticalizing distribution utility, then the output could be acquired at cost under state regulation instead of at wholesale FERC market prices. This may also be a way to help meet renewable portfolio standards.

The Connecticut legislature is considering measures to enable the distribution companies to build new power plants again. Also, in New York, which never modified the powers of distribution companies, Con Edison has repowered a plant and the NYISO has asked downstate utilities to come forward with regulated backstop solutions to impending reliability problems which include building new facilities.

Can distribution utilities build new power plants that will make energy for less than the current market rates? This may be easier said than done. New coal plants with lots of scrubbers or new gasification technology may not yield lower cost energy, particularly if natural gas prices recede.

2. Efficiency Measures to Reduce Demand. Efficiency and demand reduction are appealing solutions. Market based demand reduction measures pay some large users to interrupt their service (sending workers home) or perhaps generate with their own small plants which, though inefficient and or dirty, cost less to run than the spot market price.

The merchant generation industry may react to customers lowering their demand, however, by simply slowing the construction of new plants or by retiring existing plants, thereby keeping the supply margin tight. If spot markets are readily gamed, as some critics maintain, merchant generators might simply revise their bidding strategies to take into account the demand reduction effects and still maintain high prices.

3. Public ownership alternatives. Public power may have advantages because of superior debt credit ratings, the ability to issue long term bonds, the lack of income taxation, and no equity investors who seek returns above the level of bond interest. The cost of public acquisition could be spread out over a long period of time approximating the lifetime of the asset with bonds. Once the bonds are paid off, the output becomes available at operating cost. A private operating company could be hired to run the facilities. LIPA did this by hiring Keyspan, a private company, to operate the publicly owned LIPA utility. By financing the cost of an unused nuclear facility, the transfer to public ownership reduced rates by 20%.

The New York Power Authority stepped in to build 11 peaker plants and a new baseload plant in the New York City area to prevent shortages and price spikes when the NYISO spot market began to spike in 2000. Since then, NYPA has also built a new dual fuel baseload power plant. This public power means that less energy needs to be bought at market prices. Also, the publicly owned peakers may have the

effect of limiting market price spikes at times when demand is high. In effect, they may function as a wholesale price cap when they set the clearing price.

The Long Island Power Authority, also a public entity, has been proactive in developing new or repowered plants and transmission lines.

New Zealand, once a paradigm for restructuring, reacted to extreme prices by building a peaker plant that runs when market prices hit a certain threshold. The publicly owned peaker solutions tend to limit the price extremes, but not the underlying problem that low cost baseload plants get the peaker price when the peakers run.

Municipalities that have their own low cost power sources in their boundaries (e.g., small hydro facilities) have an advantage even if the facility does not meet all the needs, because they have to buy less in the market. They typically have the power to create municipal utilities and may be able to take existing local power plants by eminent domain. This has occurred in Green Island NY, next to Albany, and is under consideration in Auburn NY. Green Island Power Authority is attempting to obtain a license for an upstream dam owned by a merchant power producer, and has plans to rebuild the project to increase output and restore the historic Cohoes Falls, now dry.

Public power could finance and build alternative cost effective alternative energy resources, e.g., wind, landfill methane. LIPA is proposing a large offshore wind project.

4. Wholesale Energy Contract Litigation. If the state simply lets the distribution utility pass through to consumers whatever it pays to acquire energy in wholesale markets, that utility may have little incentive to seek better deals in long term contracts or to contest the rates demanded as unreasonable in violation of the Federal Power Act.

Prudence of a utility that does not seek long term contracts at reasonable rates might be questioned, though this route seems unlikely to be successful. State regulators could devise incentive systems to reward utilities who reduce costs for customers through better wholesale energy purchasing efforts and successful litigation. Distribution utilities providing default generation service could seek long term contracts for power, and if the rates demanded are too high, challenge them as unreasonable at FERC and in court.

5. Transmission Solutions. If there is a viable transmission solution, the state regulator could require a utility to build a new line, or the state itself could build it. For example, the New York Power Authority has over 1,000 miles of transmission lines, and LIPA is arranging for new transmission lines to Long Island.

New lines to reduce load pockets may yield some price benefit, in that peaker plants might run in fewer hours, but if energy is imported from another part of the state, the price might go up there. This is the Montana or Maine effect, where states that had comparatively cheap generation have now become energy farms for more expensive areas (California, Boston) and watched their home state rates go up. Same with Sweden, which had some of the world's cheapest hydro, now is selling it at market rates to Germany while raising prices in Sweden.

6. Challenge Market-Based Wholesale Rates. Typically sellers will have "market rate authority". The sellers with low cost generation (nuclear, coal, hydro) can predict that they will do very well in FERC-approved spot markets. Thus, the price these sellers demand in long term contracts is informed by their alternative of just selling into spot markets. When market rate authority is denied or taken away, the utility has to file its rates (typically set based on costs).

FERC developed a doctrine that it could set up markets that would yield just and reasonable rates if no single seller has market power to drive up prices and thus dispense with the statutory filing and opportunity to review reasonableness and revise rates. The legal foundation for the doctrine is a DC Circuit case that never determined whether FERC's regime clashes with the longstanding filed rate regulation system required by the Federal Power Act.

Federal Power Act provides that all wholesale electricity rates and contracts must be publicly filed 60 days in advance, subject to public scrutiny and FERC review for reasonableness before they take effect. No rate other than the filed rate can be charged. Traditionally these rates have been based on some measure of the cost of service (not necessarily what the spot market would pay). For sellers with market rate permission, FERC eliminated the prior filing and review and now requires only quarterly retrospective reporting of contract rates.

There are litigation opportunities when a seller owning low cost generation initially asks FERC for market rates, seeks renewal of market rate permission, or when there is a change of ownership requiring the new owner to seek market rate authority.

The auctions undertaken by some states basically commit the distribution utility to buy electricity for its retail customers from a wholesale seller who has demanded unfiled rates in secret. The winning contracts probably will not be filed 60 days in advance to allow consumer intervention at FERC. Affected customers might challenge the winning contracts as unreasonable illegally adopted. Several consumer advocates have challenged the FERC market rate regime. See http://www.pulp.tc/html/the_market_behavior_case.html