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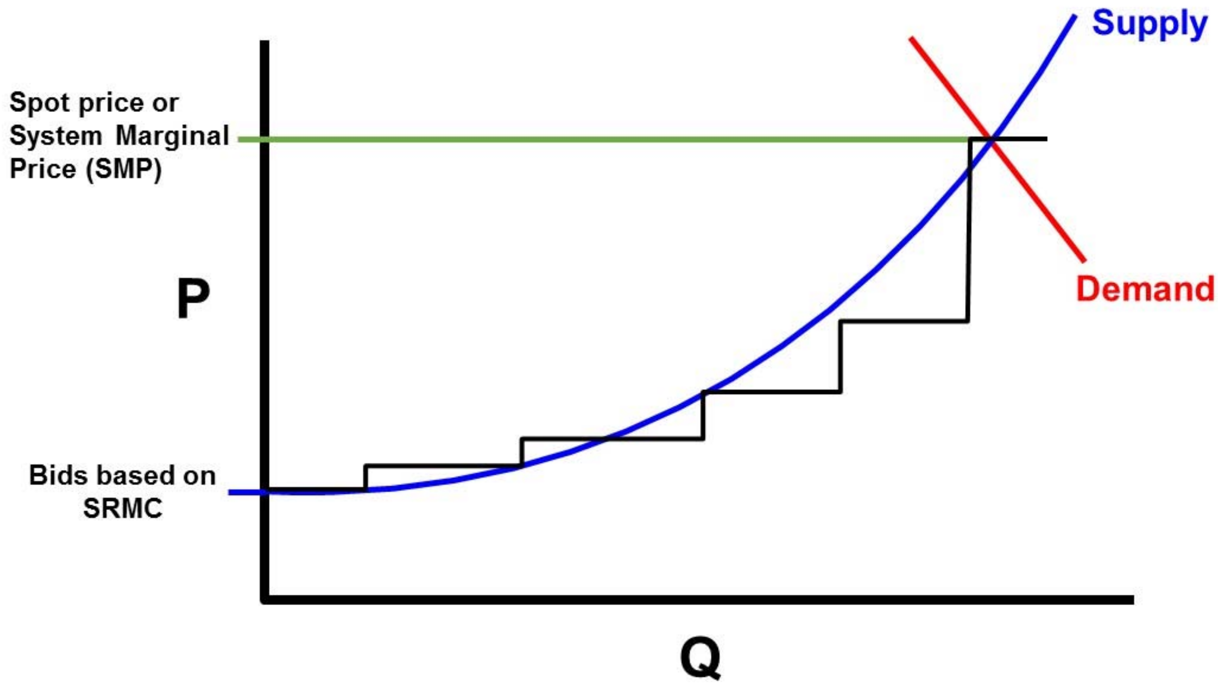
Nuclear Power & Short-Run Marginal Cost



Electricity Market Clearing

Short-Run Marginal Cost (SRMC) is an important factor in electricity markets. Bids into these markets are based on the SRMC of generators participating in the market. Bids are accepted, starting with the lowest bids, until bids accepted equal demand. All bidders are paid the System Marginal Price (SMP) or spot price that is the price of the most expensive bid selected in each trading period.

SRMC is important in understanding how electricity markets work and how merchant nuclear power plants fit into these electricity markets.

What is SRMC?

SRMC is the change in total power plant cost from a small and temporary output change, such as changing output by one MW for one hour. SRMC is in units of $/MWh.

Most power plant costs are not included in SRMC. In determining SRMC, power plant debt and financing costs, lease costs, operating costs, and other costs are considered as fixed.

SRMC for combustion-based power plants that burn coal, natural gas, or petroleum is the cost of fuel burned to generate one MWh. Thermal efficiency of combustion-based power plants changes with output level, resulting in SRMC that varies with unit output.

Wind generators, solar PV units, or run-of-river hydroelectric units have SRMC of zero. There is no change in total cost if output is changed by a small amount for a short time (i.e., all costs are fixed in the short term).

Nuclear SRMC is also zero.

Why nuclear SRMC is zero

Nuclear power plant operating and fuel costs are measured in units of $/MWh, suggesting that these operating costs and fuel costs are variable or even marginal. However, these numbers are calculated from fixed costs divided by unit output over some period (e.g., a year). Nuclear operating and fuel costs calculated this way *increase* if output is lower, a strong indication that the costs are not variable or marginal.

Calculating nuclear fuel costs in units of $/MWh allows comparisons to combustion-based generation fuel costs, but this approach is not useful in understanding nuclear power SRMC.

Nuclear fuel costs are incurred well before nuclear fuel is loaded during a refueling outage. Nuclear fuel costs are not changed by a small and temporary change in output during the operating period that follows the refueling outage.

Regulated utility ratemaking estimates nuclear fuel cost, in $/MWh, by dividing the cost of nuclear fuel for a coming operating period by the plant's ***projected*** output for the future operating period. This regulatory estimate of nuclear fuel cost is used to recover the cost of nuclear fuel in regulated rates for the future operating period. Regulatory recovery of nuclear fuel cost includes a "true-up" process after the operating period. The money collected in rates for nuclear fuel may be more or less than the actual nuclear fuel cost due to differences between actual and projected total output over the operating period. The true-up amounts are used to adjust rates in the future.

A long nuclear plant outage might delay a scheduled nuclear refueling outage, but a small change in output for a short period would not. PWR and BWR nuclear power plants shut down and conduct a refueling/maintenance outage every 18 to 24 months. A nuclear power plant refueling outage is a period of intense and highly coordinated maintenance activity that is only partly related to the actual refueling activity.

A small change in output for a short period will not change the refueling outage schedule or the fuel costs.

SRMC is key factor in electricity markets

Several decades ago, economists came up with some new ideas for electric utility and electricity industry structure. These new ideas included the possibility of introducing bid-based real-time markets for wholesale power and led to the electricity markets operating today.

These electricity markets use generator bids to decide which units to operate and to develop a market spot price (or System Marginal Price) in each trading period. In simple terms, market software considers bids and demand levels and selects bids to meet demand at the minimum spot price possible in each trading period.

Utility dispatchers do the same thing, using internal estimates of SRMC to determine the order that units will be turned on to meet demand.

Electricity markets do this based on generator bids, without other information on the costs of the generators participating in the market. Bids are based on generator SRMC and electricity market designs provide strong incentives for generators to bid at actual SRMC levels.

Electricity spot price is determined by the bid of the last unit to be dispatched (i.e., highest bid of all units operated) in each trading period. All generators with bids accepted in a trading period are paid the same spot price (i.e., not their bid price).

Payments at the spot prices for all output mean that the difference between spot price and a generator's SRMC is operating profit that can be used to cover the generator's fixed costs.

If a generator bids are set at actual SRMC, the generator will maximize its operation and operating profit.

- If a generator bids above actual SRMC, it will not be selected to run when the spot price is lower than the bid but higher than actual SRMC, with a loss in potential operating profit
- If a generator bids below actual SRMC, it will be selected to run when the spot price is at or above the bid but lower than actual SRMC, with the result being operating losses

This market approach provides generators with an opportunity to earn operating profits, but it does not guarantee that operating profits will cover actual fixed costs. Electricity spot markets do not consider information about fixed costs, annual operating profits, or other aspects of the generating units aside from bids and operation levels.

Electricity spot market activity only decides how existing generating units are dispatched, not how investments in these generation units are made, how profitable these generating units will be, or whether a generating unit continues to operate, or whether a generating unit decides to shut down.

The regional transmission organizations who operate electricity markets may also have regional reliability responsibility. These entities may take actions to help ensure that generators remain in operation or that new generation investments are made. These actions include operating separate capacity markets, putting regulatory-must-run contracts in place, and imposing reliability requirements on load-serving entities. These actions are needed because electricity market spot prices do not provide sufficient profits to owners of generating capacity to maintain desired levels of reliability.

The UK Electricity Market Reform (EMR) effort goes further and puts in place a series of incentives, payments, and contracts aimed at delivering the same amount and type of new generation (including new nuclear power plants) that would be delivered under a traditional long-term government utility planning process.

Dispatch realities

In an ideal world, power plants would be able to turn on and off instantly and be available to operate on a moment's notice. Real power plants have limits and these limits are reflected in bids to electricity markets. For example, a combustion-based power plant may only be available to operate in a particular trading period if it is already started up and at minimum load in the prior trading period.

A nuclear power plant is particularly constrained. A nuclear power plants does not simply supply a bid to the market and allow the market operator to decide whether the nuclear power plant will operate in the next trading period. Instead, nuclear power plants bid into these electricity markets as "price takers." This bidding mode allows the nuclear power plant to operate at maximum output between refueling outages. This bidding mode also means that the nuclear plant bidder will receive the spot price for all output, but does not set the spot price.

This means that the nuclear power plant is exposed to all spot prices, including negative spot prices.

Negative spot prices

How it is possible to get negative spot prices?

Renewable subsidies in the US include federal tax credits and state-based renewable energy credits. These subsidies are outside the electricity market, but based on actual project output. Outside payments linked to electricity market dispatch leads to negative SRMC.

A wind generator might receive $30/MWh in out-of-market subsidies paid based on actual output. The wind project bids into the electricity market at minus $30/MWh, a rational (and legal) response to maximize profit for the wind generator that makes a profit when the electricity spot prices is higher than negative $30/MWh. The wind generator's SRMC has shifted because of out-of-market subsidies.

In regions with a lot of wind generation, electricity spot prices become negative during times of the day and year when demand is low and there is a lot of wind (e.g., at night). These renewable subsidies could be implemented differently to provide the same financial benefit while avoiding the link to physical output and the distortion of electricity spot market prices.

Lessons for nuclear power

At a recent industry conference, I outlined the operation of electricity markets and how merchant nuclear projects fare in these markets. Some of the participants were surprised that any rational "market" would operate a wind generator rather than a nuclear power plant, given the large difference in total cost of power from these two options.

The electricity markets are only concerned about the short-term dispatch of generating units based on SRMC-based bids. These markets do not reflect fixed costs or total cost of power.

A decision to invest in a power plant may be based on total cost of power, but only if the decision-maker has a mechanism to pass the total cost of power (i.e., fixed and marginal) on to end users. A government utility or a regulated utility considering long-term capacity options may decide to invest in a nuclear power plant because the total cost of power is lower than other options.

Nuclear power plants have costs that are all fixed and an SRMC of zero. Merchant nuclear profits in electricity markets are entirely determined by the other market participants that set the spot price. When natural gas prices were high, electricity market prices were also high, and merchant nuclear units were profitable. Today, merchant nuclear projects see low profits due to lower electricity market spot prices.

The key lesson for the nuclear power industry is that all nuclear power plant costs are fixed, making electricity markets especially risky.

Contact:

Edward Kee
+1 (202) 370 7713
edk@nuclear-economics.com