Generator owned energy storage system can increase system cost: cause and solution

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Abstract

Despite the benefits the energy storage system can bring to the electric system, they can also increase the system cost by pushing the market price higher if they are owned by some large generators. In this paper, we use a unit commitment model to simulate such a situation with the 2018 Electric Reliability Council of Texas (ERCOT) data. Most of the generating units will earn less if the storage system is operated to shave the peak demand, and they have the incentive to own the storage system using its revenue to compensate for generators. Moreover, once they own the storage system, some of the large generators have the incentive to self-schedule the storage system as the price taker to push the peak net demand higher or to enlarge the system ramping demand. The extra profits from such altered demand profile can compensate for the loss including opportunity cost from the storage system. Both to push peak demand higher and to enlarge the system ramping demand will increase the average electricity price over the year in our simulation. To prevent such a situation, the prohibition for the generating company to own the energy storage system is effective. To encourage competition among the energy storage system can also mitigate the risk of energy storage systems increasing the system cost.

Introduction

Since an energy storage system (ESS) can provide flexibility, help to integrate more renewables, and reduce price fluctuation, it has received a lot of attention in the current energy transition background with considerable penetration of intermittent resources. Many researchers have explored its revenue potential in energy arbitrage\textsuperscript{1,2} and other revenue streams\textsuperscript{3,4}, showing attractive profitability. However, many of these research projects regard the ESS as a price taker and many of them only focus on the benefit of the whole grid system or the owner of ESS, ignoring the conflicts in profits of different players in the market.
A few studies\textsuperscript{5–8} proved that ESS’s operation has a significant impact on the electricity price. It would be natural to think about the possibility that the owner utilizes the ESS to push the peak price even higher for more profit if he owns many other generation assets. Sioshansi\textsuperscript{9} proved that ESS could reduce the social welfare if it was owned by generators rather than the system operator. Deboever\textsuperscript{10} demonstrated that adding ESS would increase social welfare no matter who operates it, but the operation and ownership would affect the amount of the additional social welfare. However, these discussions are based on short-term simulation, a day or a week. Schill\textsuperscript{11} constructed a more detailed model and simulated on a longer period, arriving at a similar conclusion. All these previous researches ignored the complexity of the electric system, including constraints like minimum down time of plant operation, and cost like start-up cost. The minimum down time constraint will limit the ability of the grid to handle large ramp events, which can be mitigated or exacerbated by the operation of energy storage. The start-up cost will be a concern with considerable penetration of variable renewables and the start-up cost is expected to increase by 119\% in 2030 in Germany\textsuperscript{12}.

In this paper, we will take all these complexities of the grid into consideration, simulate different operation strategies of the ESS if it is owned by a larger generator, and analyze how it will affect the system cost and the profit of the owner. Then we will propose preliminary measures to avoid the additional market cost from ESS operation.

\textbf{Data and Method}

Due to the complexity of the grid system, it is challenging to derive an analytic expression for the optimal operation strategy of the ESS when it is owned by the massive generators. Hence, we only simulate the operation of ESS under three strategies: 1) peak-shaving, 2) load-leveraging, 3) ramp-enlarging, and compare with the baseline. The baseline is to operate the system without ESS. The first strategy is to sell when demand is high and to buy low, which has been demonstrated as a suboptimal strategy\textsuperscript{9}, but it still brings down the system cost. Another is that the ESS buys electricity at peak demand to push price higher for higher profits of other generators and sells at the second-highest demand. The third strategy, not yet seen in the previous research, is that ESS increases the ramping need, rather than reducing it, to make the flexible generator to earn more profits possibly. At the largest ramping up event, it will charge to enlarge the ramping need and similarly, it will discharge in the largest ramping down event. In the latter two strategies, the ESS will face a loss, but we expect the extra profits from some generators can cover such loss, giving them an incentive to take the ownership of the ESS.

There are two steps for the simulation: ESS self-scheduling and market-clearing. We assume the ESS will self-schedule one-hour charging and one-hour discharging every day at full capacity with 80\% round trip efficiency under the three strategies. It will directly alter the net demand profile. Taking the net demand profile as an input, the market-clearing process is to minimize the system cost via the Unit Commitment and Economic Dispatch (UCED) model. The model will include 1) demand-supply constraint; 2) ramp rate constraint; 3) maximum and minimum output constraint; 4) minimum down and up time constraints. The system cost is composed by start-up cost, variable operation cost, and the fixed online cost. The variable
operation cost is simplified as the sum of fuel cost and other variable operation cost. The fixed online cost is calculated based on the fuel consumption when power output equals zero.

\[
\text{Minimize: } \sum_t \sum_u C_{u,t}^{\text{fuel}} + C_{u,t}^{\text{VOM}} + C_{u,t}^{\text{fix}} = \min_{x,y,z,P} \sum_t \sum_u x_{u,t} \cdot P_{u,t} \cdot \text{price}_{\text{fuel},u} + x_{u,t} \cdot P_{u,t} \cdot C_{u,t}^{\text{VOM}} + x_{u,t} \cdot C_{u,t}^{\text{fix}} + y_{u,t} \cdot C_{u,t}^{\text{start}}
\]

s.t.

\[
\forall t, \quad \sum_u P_{u,t} = \text{Net Demand}_t
\]

\[
\forall u, t = 1, \quad y_{u,1} - x_{u,1} - z_{u,1} = 0
\]

\[
\forall u, \forall t > 1, \quad y_{u,t} - x_{u,t} - z_{u,t} + x_{u,t-1} = 0
\]

\[
\forall u, \forall t, \quad P_{u,t} - x_{u,t} \cdot P_{u,\text{max}} \leq 0
\]

\[
\forall u, \forall t, \quad x_{u,t} \cdot P_{u,\text{min}} - P_{u,t} \leq 0
\]

\[
\forall u, \forall t, \quad |P_{u,t} - P_{u,t-1}| - R_{\text{max},u} \leq 0
\]

\[
\forall u, \forall t, \quad y_{u,t} + \sum_{j=t}^{\min(t+\min \text{ up time},T)} z_{u,j} - 1 \leq 0
\]

\[
\forall u, \forall t, \quad z_{u,t} + \sum_{j=t}^{\min(t+\min \text{ down time},T)} y_{u,j} - 1 \leq 0
\]

\[
P_{u,t}: \text{ Power output of unit u at hour t, MW;}
\]

\[
P_{u,\text{min}}: \text{ Minimum stable power output for unit u, MW;}
\]

\[
P_{u,\text{max}}: \text{ Maximum power output, which is installed capacity, for unit u, MW;}
\]

\[
x_{u,t}: \text{ If unit u is online at hour t, x=1; Otherwise, x=0;}
\]

\[
y_{u,t}: \text{ If unit u is starting up at hour t, y=1; Otherwise, y=0;}
\]

\[
z_{u,t}: \text{ If unit u is shutting down at hour t, z=1; Otherwise, z=0;}
\]

\[
\text{price}_{\text{fuel},u}: \text{ Fuel price for unit u, $/MWh;}
\]

\[
c_{u}^{\text{VOM}}: \text{ Other variable cost for unit u, $/MWh;}
\]
Maximum ramp rate of unit u, MW/h;

Fuel cost of unit u at hour t, $;

Other variable operation cost for unit u at hour t, $;

Startup cost of unit u, $;

Fixed online cost of unit u, $/hr;

The market-clearing price will be the operation cost of the marginal dispatched unit and uniformed for the whole system since no congestion is considered in our simulation. The revenue for each unit is the production or consumption multiplied by the marginal price and the profit is the revenue minus the cost since no other compensation mechanism like uplift is considered in our simulation. For simplicity, we only simulate an energy-only market and no reserve nor other ancillary services. We also assume no curtailment from solar and wind resources. Another strong assumption here is that the ESS operator will know the net demand profile in advance, which will be changed to a more realistic one in our future research.

The model simulates the grid operation for a whole year and adopts the system setting of ERCOT in 2018, with historical hourly demand and wind generation. The hourly solar generation is simulated via PVWatts® due to the lack of historical data. No import nor export of the electricity is considered. The hydrological impact on the hydropower generation is ignored and all the hydropower units are regarded as dispatchable. The capability of plants and cost information come from existing research. Existing ESS in ERCOT is replaced with a single pumped storage plant with capacity as 344.5MW, 0.5% of ERCOT peak net demand in 2018. The result of the simulation can also apply to other energy storage technologies since they have similar operation characteristics.

Result

When the market is operated without the ESS, the total market cost is about 8.57 billion dollars, significantly lower to the realistic one since we only consider the energy market without import/export and no other ancillary services. Within it, the startup cost is about 0.18 billion dollars, the fixed online cost is about 1.2 billion, and the remaining 7.1 billion dollars are the generation cost including the fuel cost and variable operation cost. As shown in Table 1, the peak-shaving strategy reduces the system cost, and the other two strategies increase the system cost. The cost change is small, around 0.05% of the total system cost, but it only comes from the operation strategy of an ESS as 0.5% of the peak demand. Besides the impact on the generation cost, the ESS also impose comparable changes in the startup cost and online cost due to the complexity of the grid system.

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1 PVWatts® Calculator: https://pvwatts.nrel.gov/
As for individual plants, 342 out of 603 dispatchable units and all the solar and wind units will earn less if the ESS is introduced into the system and operated under the peak-shaving strategy, although the ESS makes profits around half million dollars. Under the other two strategies, the ESS face a loss of one million dollars, and many generators earn more profit. Among these generators, 5 units have the incentive to convince the ESS to shift from peak-shaving to load-leveraging, and 4 units have the motivation to convince the ESS to shift from peak-shaving to ramp-enlarging. In other words, the extra profit and the avoided loss made by one generator from ESS strategy shifting is larger than the loss of ESS. Among these individual units, they all have a large capacity (>500MW). However, not all the large units nor high-cost units have the incentive for ESS strategy shifting. If several generators share their revenues, more players have the incentive to convince the ESS to shift from peak-shaving to other strategies. In terms of plant types, as shown in Table 2, the all types of generators will earn less in the peak-shaving strategy. The natural gas plants do not benefit the most from ramp-enlarging strategy, and the extra profit even lower than the coal plants. It may due to the flexibility of coal power plants is not significantly worse than the natural gas plant on the hourly level but the simulation is on hourly. The negative profit change of oil units in ramp-enlarging strategy is due to the fact that the oil units are not dispatched in other scenarios and when they are dispatched at the marginal price can not cover their operation cost. We assume all units bid on the marginal cost, not the average cost or other bidding strategies.

<table>
<thead>
<tr>
<th>$/MW</th>
<th>Capacity (MW)</th>
<th>(1) Peak-shaving</th>
<th>(2) Load-leveraging</th>
<th>(3) Ramp-enlarging</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass</td>
<td>117.5</td>
<td>-459.97</td>
<td>52.22</td>
<td>402.17</td>
</tr>
<tr>
<td>Coal</td>
<td>14151.6</td>
<td>-138.33</td>
<td>1121.59</td>
<td>1025.95</td>
</tr>
<tr>
<td>Hydro</td>
<td>547.8</td>
<td>-277.56</td>
<td>1538.07</td>
<td>1242.09</td>
</tr>
<tr>
<td>Landfill</td>
<td>70.9</td>
<td>-265.06</td>
<td>1545.39</td>
<td>1248.80</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>56478.1</td>
<td>-64.63</td>
<td>560.23</td>
<td>572.03</td>
</tr>
<tr>
<td>Oil</td>
<td>26.7</td>
<td>0.00</td>
<td>0.00</td>
<td>-6.62</td>
</tr>
<tr>
<td>Ur</td>
<td>4960</td>
<td>-278.97</td>
<td>1542.75</td>
<td>1244.55</td>
</tr>
<tr>
<td>Non-fossil Waste</td>
<td>90.7</td>
<td>-268.19</td>
<td>1542.55</td>
<td>1239.06</td>
</tr>
<tr>
<td>Storage</td>
<td>344.5</td>
<td>1210.38</td>
<td>-3494.00</td>
<td>-3030.07</td>
</tr>
<tr>
<td>Wind</td>
<td>22704.6</td>
<td>-155.01</td>
<td>452.25</td>
<td>394.25</td>
</tr>
<tr>
<td>Solar</td>
<td>1358.5</td>
<td>-67.01</td>
<td>181.34</td>
<td>145.01</td>
</tr>
</tbody>
</table>

Table 1 System cost changes under different ESS strategies

Table 2 Profit changes under different ESS strategies

The differences in profits come from different dispatch decision and the market price. Although we expect the load-leveraging strategy will always increase the price, it sometimes reduces the price at the peak net demand time, since the system will have some flexibility to mitigate the impact from higher demand. However, over the whole year, both the load-leveraging strategy and the ramp-enlarging strategy increase the average price by 0.17$/kWh and 0.14$/kWh.
Discussion

The results reveal the incentives for the generators to own a storage system. When the storage system shaves the demand peak, all the generators earn less and to hold a storage system, they can reduce their loss, but to take the ownership cannot compensate the loss of all the generators, because of the reduced market price and system cost overall. However, in another case, the generators have the incentive to take control of the storage system to increase the system cost by either increasing the peak demand or the need for ramping. The extra profits from generators can compensate for the loss of storage, and many generators will benefit from it. It is evident that the first incentive and practice bring more benefit to the customers, and the latter may not be encouraged.

Both practices seem possible under the current market design in the U.S. FERC order 841 grants the right for the energy storage system, including behind meter storages and storages at the distribution level to participate in the wholesale market. The order also gives them the right to be self-scheduled resources when they are the price takers.

In terms of the system cost, we hope to prevent the generators using ESS to increase the peak demand or to increase the need for ramping. Although it will bring the most substantial reduction to the system cost, it is difficult to ask all the ESSs subject to the dispatching decision from the system operator. To prohibit the generating company from owning the storage system or limiting the capacity of storage that a generator can hold is another measurement, but we foresee the difficulties to implement this prohibition. A more practical solution is to encourage competition among storage system themselves.

<table>
<thead>
<tr>
<th>(A, B) unit: thousand $</th>
<th>Peak-shaving</th>
<th>Ramp-enlarging</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak-shaving</td>
<td>(208, 208)</td>
<td>(240, -519)</td>
</tr>
<tr>
<td>Ramp-enlarging</td>
<td>(-519, 240)</td>
<td>(-521, -521)</td>
</tr>
</tbody>
</table>

*Table 3 Revenue of two ESSs under different strategies*

Once the ESS in our simulation is split into two systems with equal capacity, 172.25MW and one adopts the peak-shaving strategy, and another adopts the ramp-enlarging strategy, the system cost will reduce only ten thousand dollars and only 95 units earn less than the reference scenario. The cost reduction is much smaller than the peak-shaving strategy. As shown in Table 3 the storage with peak shaving will earn about $0.2 million profit, about $15% higher than the situation that all the ESS adopts the peak-shaving strategy. The other one will lose $0.5 million, and it loses about $2000 more than when all ESSs adopts the ramp-enlarging strategy. In this case, there still five units have the incentive to collaborate or to own an ESS and to convert from peak-shaving to ramp-enlarging when the other ESS uses peak-shaving strategy. However, their incentive, the extra profit, is lower than the monopoly situation.

The benefits, higher prices, resulting from ESS are spread over the market. Many generators can be the free riders and prefer other generators to adopt an ESS to push price higher.
The first ESS deployed in the market will have the largest market power since there is no competition. However, if the first one chooses the load-leveraging or ramp-enlarging strategy, more ESSs with peak-shaving strategy are encouraged to participate in the market since they can earn more. In the real market, the competition will be more complicated, but we believe that at least if one ESS can choose the peak-shaving strategy, ESS with the other two strategies will be hard to survive.

**Bibliography**


