Energy Storage and Distributed Energy Resources Phase 4 (ESDER 4) Straw Proposal

Initial Comments by Department of Market Monitoring
May 21, 2019

Summary

DMM appreciates the opportunity to comment on the ISO's *Energy Storage and Distributed Energy Resources Phase 4 (ESDER4) Straw Proposal*. DMM plans to submit comments on the straw proposal in two parts. This document is the first part of these comments. In these initial comments, DMM provides input on the straw proposal for market power mitigation of energy storage. DMM plans to submit comments on the other aspects of the straw proposal at a later date.

DMM supports the ISO's proposal to make energy storage resources subject to local market power mitigation. This is an important issue and DMM appreciates the ISO's continued commitment to pursuing it as part of the ESDER 4 initiative. DMM also supports the ISO's efforts to create a default energy bid (DEB) for energy storage resources.

In these initial comments, DMM identifies several elements of the proposed DEB approach that warrant further consideration and discussion. A draft DMM whitepaper outlining a potential general framework for estimation of short run marginal cost for energy storage resources is included as an attachment to these comments.

I. Market Power Mitigation for Energy Storage

DMM supports the ISO's proposal to make energy storage resources subject to local market power mitigation. DMM also supports the ISO's efforts to create a default energy bid (DEB) approach that appropriately reflects marginal costs of energy storage resources. However, the approach for determining DEBs presented in the straw proposal does not appear to be a general representation of marginal cost for an energy storage resource.

The DEB approach presented in the straw proposal appears to be designed to identify a price high enough to limit the number of daily cycles of a lithium-ion battery to a desired frequency. This is very different from an approach that attempts to estimate marginal cost (inclusive of opportunity costs) in a way that could accommodate many different energy storage technologies. Additionally, the approach in the straw proposal does not appear to consider opportunity costs that derive from the physical characteristics of energy storage resources. Finally, the approach does not accommodate differences in costs between the charging and discharging ranges of energy storage resources.

There are efficiency benefits to more directly estimating opportunity cost based on physical limitations of the resource at a point in time and expected future profit opportunities, and identifying and explicitly including other costs where appropriate. This type of approach would facilitate more efficient market outcomes and profit maximization for the storage resource operator. DMM has developed a general framework approach that could help to accomplish this goal. Details of this framework are presented in a draft whitepaper attached to these comments. This framework is not limited in applicability to lithium-ion batteries, and is general enough to apply to a variety of energy storage technologies and duration capabilities.

DEBs should reflect marginal cost

The purpose of a DEB is to serve as a close estimate of marginal cost for use in market power mitigation processes. The ISO explicitly recognizes this point in the stakeholder call presentation from May 7, 2019.[1] For energy storage resources, the marginal cost may include explicit costs similar to other resource types, as well as opportunity costs resulting from the physical characteristics of energy storage resources.

Energy storage resources have a limited ability to store energy for later discharge and a resource's state-of-charge at a given time limits its discharge capability. When an energy storage resource discharges, it must recharge before it can discharge that quantity again. These attributes create potential opportunity costs of foregone profits if discharging or charging occurs at a time that is not profit maximizing over the day.

This type of opportunity cost is unique to energy storage resources, and is distinct from contract-based costs that may be incurred by operating in a particular manner. Opportunity costs need to be estimated, considering all applicable profit opportunities over the day, and reflected in DEBs for energy storage resources.

The ISO's proposed approach for an energy storage DEB does not appear to reflect the intent of estimating marginal cost of an energy storage resource, nor does it appear to consider multiple technology types. Instead, the proposed approach appears to have the purpose of setting a DEB high enough to limit cycling of a lithium-ion battery to one cycle per day. This is suggested in the ISO's stakeholder call presentation, which notes that "Anecdotally, the ISO found that many LI batteries could operate profitably by cycling once per day."[2]

As an initial point, anecdotal evidence should not be viewed as sufficient support for a DEB value. This would be inconsistent with the standard applied to traditional generators which must provide actual, verifiable data on unit characteristics and costs.

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[1] *Energy Storage and Distributed Energy Resources Phase 4, Straw Proposal, Stakeholder Web Conference,* California ISO, May 7, 2019. http://www.caiso.com/Documents/Presentation-EnergyStorageandDistributedEnergyResourcesPhase4-May72019.pdf

[2] Ibid, slide 23.

Furthermore, previous stakeholder discussions suggest that the origin of the assumption about one cycle per day is that this reflects negotiated warranty agreements. These agreements anticipate that a set number of cycles will occur over a determined period of time, after which cell augmentation will be required to maintain the capacity of the battery. If energy storage resource operators incur costs associated with cycling (e.g., additional maintenance), explicit identification and modeling of that cost will result in more efficient use of the resource.

Market rules that are designed to facilitate limited cycling of energy storage resources to accommodate contractual agreements, without considering the cost of cycling, create incentives for an operator of an energy storage resource to enter lower cost warranty agreements with a limited number of cycles over a relatively long period of time. This could allow the operator to provide low cost, but relatively inflexible capacity for a longer time period. However, when all costs are appropriately modeled in the market optimization, the full flexibility of energy storage resources can be realized as costs are optimized as needed to achieve more efficient market outcomes.

DEBs for energy storage resources need to reflect different costs on charging and discharging operating ranges.

DMM supports the ISO's proposal to calculate DEBs and subject market bids of energy storage resources to potential mitigation across both discharging and charging operating ranges. The need for mitigation on the discharging range is straightforward and analogous to a traditional generator.

On the charging range, the need for market power mitigation arises from the ability to withhold counterflow to a binding constraint through uneconomic charging. When an energy storage resource that is modeled as a generator reduces its level of charging, the flow impact on constraints to which the resource has a negative shift factor is equivalent to that of an injection by a generator.

Because of this, the impact of a storage resource submitting a very high bid to charge is equivalent to a generator submitting a very high bid to produce incremental energy. Therefore, an energy storage resource can exercise market power as a generator by charging when it is uneconomic to do so. This results in the need to mitigate energy storage resources on the full operating range of the resource.

The ISO's proposal for an energy storage DEB would result in a single DEB value applied to both charging and discharging operating ranges. However, the costs associated with each operating range may be different, and the use of a single value may result in unintended dispatch consequences when the resource is mitigated.

For example, if a resource is charging and mitigated to the single DEB value, the resource may then be dispatched to switch from charging to discharging. This outcome may be both inefficient for the market and not profit maximizing for the resource operator if the costs associated with the two operating ranges differ.

By accurately representing differences in costs of the charging and discharging range of the resource, there exists the possibility that mitigation in this example could result in the resource ceasing to charge, but not switching to discharge. This outcome would be appropriate and profit maximizing for the resource when costs differ across the two operating ranges, and the LMP exceeds marginal cost on the charging range, but is below marginal cost to discharge.

A more complete modeling of costs is appropriate and feasible

In the straw proposal, the ISO states that one default energy bid option would be to model all costs for battery resources, similar to how gas resources are currently modeled with the variable cost default energy bid option. This default energy bid option would account for explicit costs and attempt to estimate opportunity costs.

DMM supports this type of approach over the proposed approach, which appears to be designed to limit cycling of lithium-ion batteries. A default energy bid that attempted to model the costs would come closer to capturing the true marginal cost of a variety of energy storage resources. It would also hold energy storage resources to the same standard as other generators, which are required to have DEBs based on verifiable physical characteristics and cost data.

The straw proposal states that developing this option for an energy storage DEB was not favored by the ISO as it was determined to be "overly complex for storage resources". Given the increasing role of energy storage resources in the ISO market, it is important to develop a robust and reasonably accurate estimate of marginal cost for energy storage resources. Further, while a level of additional computation would be required, perhaps the greatest increase in complexity and computational effort is already included in the ISO's DEB proposal: the use of a robust price forecast.

At least two other ISO/RTO markets (NYISO and SPP) have proposed approaches to estimate cost-based energy bids for energy storage resources that capture opportunity costs, and allow inclusion of other costs as appropriate.[3,4] Although these approaches make some necessary

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[3] Southwest Power Pool, Inc., Docket No. ER19-460-000, Order 841 Compliance Filing. Revisions to Attachment AF, Section 3.2 (I). https://www.spp.org/documents/59108/20181203_order%20no.%20841%20compliance%20filing_er19-460-000.pdf

[4] New York Independent System Operator, Inc. Response to FERC questions on ESRs (Order No. 841) Docket No. ER19-467-000, Pages 9-13, NYISO Response to Commission Question 4(b). https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15236421

simplifying assumptions for implementation purposes, they are based on the concept of estimating opportunity costs that derive from the physical nature of energy storage resources.

Given the comparatively significant and increasing volume of energy storage resources in the ISO market, the ISO should be well-positioned to expand upon approaches to the estimation of energy storage marginal cost proposed elsewhere and develop a more general approach to estimating marginal cost of energy storage resources for use as a DEB. A draft DMM whitepaper outlining the details of one potential framework to estimate marginal cost of energy storage resources is attached to these comments. Even if some level of simplifying assumption is initially required to facilitate implementation, adopting a robust framework now leaves room to relax assumptions as feasible in the future to improve marginal cost estimates.

DRAFT

Generalized estimation of short run marginal cost for energy storage resources

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Introduction

The rationale for using opportunity costs to estimate short run marginal costs of energy storage resources is that dispatch in one interval may only be possible by forgoing profit opportunities in a future interval. If the storage resource operator maximizes profit over some period of time (e.g., a day), then an appropriate estimate of short run marginal cost is one that covers the marginal opportunity cost of a dispatch that deviates from the expected profit maximizing dispatch over the day.

The problem of estimating short run marginal cost for energy storage resources can be complex and depends on several inputs that change through time. The opportunity cost of dispatch actions will vary over time depending on state-of-charge, the power and energy ratings of the storage resource, and profit opportunities and prices expected later in the day or optimization period.

Work published by the Southwest Power Pool Market Monitoring Unit (SPP MMU)[1] presents details of an approach that simplifies the problem for a storage resource of 1-hour duration, or a longer duration storage resource with some stronger implicit assumptions about the state-of-charge at a given point in time. Southwest Power Pool (SPP) and New York ISO (NYISO) each proposed the use of an approach very similar to that presented by the SPP MMU for calculating cost based energy bids in filings for compliance with FERC Order 841[2,3].

Approaches being proposed in these markets have merit in their relative ease of implementation and since they provide theoretically robust estimates for resources that fit the assumptions of each approach. These approaches also develop many concepts that apply more generally to marginal costs faced by energy storage resources. However, all of these approaches are best suited for short duration resources (e.g., 1 hour), and only consider opportunity costs from foregone energy arbitrage opportunities later in the day.

For some applications, a more general or comprehensive estimate of short run marginal cost may be required. A generalized estimate of short run marginal cost can be calculated by solving a more general optimization problem for each hour of the operating day. The more general approach can also be used as the basis for a cost-based bid in market power mitigation processes.

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[1] Southwest Power Pool - Market Monitoring Unit, A. Swadley. "Dynamic Opportunity Cost Mitigated Energy Offer Framework for Electric Storage Resources", August 24, 2018. https://www.spp.org/documents/58525/dynamic%20opp%20cost%20esr%20mitigated%20offer%20framework_20180824.pdf

[2] Southwest Power Pool, Inc., Docket No. ER19-460-000, Order 841 Compliance Filing. Revisions to Attachment AF, Section 3.2 (I). https://www.spp.org/documents/59108/20181203_order%20no.%20841%20compliance%20filing_er19-460-000.pdf

[3] New York Independent System Operator, Inc. Response to FERC questions on ESRs (Order No. 841) Docket No. ER19-467-000, Pages 9-13, NYISO Response to Commission Question 4(b). https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15236421

This paper presents a framework to solve the more general problem of estimating short run marginal cost for a storage resource of any duration, taking any initial state-of-charge as an input, and where it may be appropriate to consider additional profit opportunities beyond energy arbitrage. While the more general approach requires increased computational effort, the increased precision of the marginal cost estimate may be more appropriate for longer duration storage resources and for resources with more complex profit structures.

Background

A battery storage resource will maximize expected profits over a day or other time period by identifying a series of profit maximizing dispatches to charge, discharge, or take no action for each interval over the period. The maximized profit function will include information on explicit costs such as charging cost (where applicable) and potentially other maintenance costs as well. The profit function will also include any resource constraints that necessitate tradeoffs among profit opportunities at different points in time. By recognizing the temporal limitations of the resource, these constraints provide additional implicit cost information. The additional information from constraints allows the profit maximization problem to reflect of opportunity costs associated with tradeoffs across time.

In a competitive market, the lowest price at which production of an additional unit of any good may be expected is the marginal cost of producing the additional unit of that good. A battery storage resource modeled as a generator produces incremental energy by discharging or by decreasing its level of charging[4]. Therefore, for a battery storage resource, the energy dispatch in each hour of an expected profit maximizing dispatch solution will align with the resource's marginal cost of energy production in that hour: if the marginal cost exceeds price in a given hour, the dispatch will not occur.

The profit maximizing dispatch derived from a profit function that includes all constraints and captures all explicit costs is the same dispatch that would be expected when a resource bids marginal cost inclusive of opportunity cost in each hour. It follows that marginal cost for a given hour and output range can be estimated by determining the price at which the profit maximizing dispatch for that hour would change. For a set of expected prices, the price above or below which the expected profit maximizing dispatch for hour j changes is an estimate marginal cost for that operating range in that hour. Marginal cost estimated in this way will reflect explicit costs included in the profit maximization problem, as well as opportunity costs from foregone future profits[5].

[4] This document is considering an energy storage resource where the full operating range of the resource is modeled as a generator, such as CAISO's NGR model. For an energy storage resource modeled as a generator, the marginal cost of incremental generation is of interest. On the charging range of the resource, the battery can have flow impact equivalent to incremental generation by decreasing its level of charging. Therefore, a battery could exercise market power in generation by submitting a very high bid to charge. The purpose in estimating short run marginal cost for this operating range is to determine how high the price would need to be before it is no longer economic for the resource to charge (i.e., withhold counterflow to a constraint).

[5] In addition to the more generally applicable explanation here, this result is shown in more detail for the case of a 1-hour duration battery in: Southwest Power Pool - Market Monitoring Unit, A. Swadley. "Dynamic Opportunity Cost Mitigated Energy Offer Framework for Electric Storage Resources", August 24, 2018. https://www.spp.org/documents/58525/dynamic%20opp%20cost%20esr%20mitigated%20offer%20framework_20180824.pdf

Estimation process

Step 1.

Given an assumed state-of-charge at the beginning of hour j, S_0 , and an expectation of prices for all remaining hours of the day, $i = \{j, \ldots, N\}$, solve for the maximum expected profit, π^* , and the associated hourly dispatch, by solving the following problem[6]:

$$\max_{C,D,S} \sum_{i=j}^{N} P_i(D_i - C_i) \tag{1}$$

$$= \max_{C,D,S} P_j\left(D_j - C_j\right) + \sum_{i=j+1}^{N} P_i(D_i - C_i)$$

s.to:

$$S_j = S_0 + \eta C_j - D_j$$

$$S_{i \neq j} = S_{i-1} + \eta C_i - D_i$$

$$0 \leq D_i \leq k$$

$$0 \leq C_i \leq l$$

$$0 \leq \eta \leq 1$$

$$0 \leq S_i \leq hk$$

$$C_i D_i = 0$$

where D_i represents the level of discharging in hour i, C_i represents the level of charging in hour i, S_0 represents the assumed state-of-charge at the beginning of hour j, S_j represents the state-of-charge at the end of hour j (in MWh) , $S_{i \neq j}$ represents the state-of-charge at the end of hour i (in MWh) for all hours $i \neq j$, η represents the roundtrip efficiency loss factor, h represents charge or discharge duration capability of the energy storage resource in hours, k represents the maximum power level of discharge, and l represents the maximum level of charge. Note that while the problem as presented here considers only profit opportunities from energy arbitrage in future intervals of the period, the problem is a general form that could also include other profit opportunities, for example, the ability to provide ancillary services in a later hour.

Step 2.

If the expected profit maximizing dispatch for the rest of the day includes a dispatch in hour j to charge $(C_j > 0)$ or discharge $(D_j > 0)$, continue with Step 2. If the expected profit maximizing solution results in $D_j = C_j = 0$, move directly to Step 3.

If the series of expected profit maximizing dispatches for the rest of the day includes a dispatch in hour j to charge or discharge, this dispatch is required to achieve maximum profit value given expected prices.

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[6] Basic profit maximization problem adapted from: B.C. Salles, M., Huang, J., Aziz, M., and Hogan, W., 2017. Potential Arbitrage Revenue of Energy Storage Systems in PJM. Energies 10(8), 1100. http://www.mdpi.com/1996-1073/10/8/1100/pdf.

However, the dispatch will be profit maximizing only to the extent that it aligns with the resource's marginal cost for the operating range.

If the expected profit maximizing dispatch is to discharge in hour j, this implies that the expected price in the hour exceeds the marginal cost of discharge in that hour. If the realized price is below the marginal cost of discharging, the resource would instead maximize profit by forgoing the discharge in that hour in favor of the second-best expected profit.

If the expected profit maximizing dispatch in hour j is to charge, this implies that the expected price in the hour is below the marginal cost of forgone charging. Charging in a particular hour may be profit maximizing if the expected price in the hour is among the lowest cost opportunities to charge before reaching a profit maximizing discharge opportunity. The cost of foregone charging will reflect the opportunity cost of profit given up if the charging opportunity is foregone. If the realized price is above the marginal cost of forgone charging, the resource would maximize profit by forgoing charging in favor of the second-best expected profit.

For each of these scenarios then, the next step is to calculate the second-best expected profit as if the profit maximizing dispatch did not occur. This value will be used in a later step to determine the minimum price at which discharge in hour j remains profit maximizing, or the price above which it becomes profit maximizing to forgo charging. The latter value is equivalent to the maximum price at which charging in hour j remains profit maximizing.

Potential candidate scenarios for second-best profit are dependent on beginning of hour state-of-charge, S_0 . If $0 < S_0 < hk$, and the expected profit maximizing dispatch in hour j is to discharge, the second-best expected profit may be derived from 0 MW dispatch in hour j, or from charging in hour j. Analogous logic applies if the expected profit maximizing dispatch in hour j is to charge.

In these scenarios, calculate maximum profit that could be expected from each possibility by solving problem (1) again with C_j or D_j constrained as appropriate, and retain the greater value as the overall second-best expected profit, π'. If $S_0 = 0$, and the expected profit maximizing dispatch in hour j is to charge, the second-best profit can only be achieved by no dispatch in hour j because the resource has no capability to discharge in hour j. Similarly, if $S_0 = hk$, and the expected profit maximizing dispatch in hour j is to discharge, the second-best profit can only be achieved by no dispatch in hour j since the resource has no capability to charge in hour j.

Step 3.

For cases when the expected profit maximizing solution is no dispatch in hour j, charging or discharging in hour j is not required to achieve maximum profit given expected prices. This output level of 0 MW will also be profit maximizing only to the extent that it aligns with the resource's marginal cost. A profit maximizing output of 0 MW in hour j implies that the expected price exceeds the marginal cost of forgone charging, but the expected price is below the marginal cost of discharging in hour j.

To determine the opportunity cost based estimate of short run marginal cost for each operating range of the resource (charge or discharge), find the minimum (discharging) or maximum (charging) price at which a non-zero dispatch in hour j could be profit maximizing, and still result in the expected maximum profit. This is accomplished by using the value of π^* from Step 1 to solve the optimization problem (2), presented below. Problem (2) is subject to the same constraints as (1), and additional constraints on charging and discharging in hour j.

When calculating the marginal cost estimate for the discharge range, constrain D_j to the maximum level achievable given S_0 . Similarly, when calculating the marginal cost estimate for the charging range, constrain C_j to the maximum level achievable given S_0. Estimates of marginal cost are only applicable for dispatch that is feasible given S_0. For example, if S_0 = 0, no estimate of marginal cost would be calculated for discharging in hour j because discharge is not feasible given the state-of-charge. Note that problem (2) is just a variation of problem (1), with terms rearranged and different values held constant. Minimize problem (2) when calculating for the discharging range, and maximize when calculating for the charging range.

$$\underset{C,D,S}{\text{Max/Min}} \; P_j = \frac{\pi^* - \sum_{i=j+1}^{N} P_i (D_i - C_i)}{(D_j - C_j)} \tag{2}$$

$$\text{s.to} \qquad \text{Constraints of problem (1), and}$$

$$D_j = \overline{D_J}$$

$$\text{or}$$

$$C_j = \overline{C_J}$$

For cases when the expected profit maximizing solution is a non-zero dispatch of charging or discharging in hour j, the solving process is similar to the case of 0 MW dispatch in hour j. The marginal cost estimate is still solved from problem (2), however the second-best expected profit, π', is used in place of π^*.

If the expected profit maximizing dispatch in hour j is to discharge, minimize problem (2) with D_j constrained expected profit maximizing dispatch when solving the marginal cost estimate for the discharge range. Minimizing problem (2) using second-best profit and constraining in this manner determines the lowest price at which the resource could discharge in hour j and still maximize expected profit. If realized prices in hour j are below the solved value, expected profit is instead maximized when discharge does not occur in hour j, and the second-best expected profit becomes the maximum expected profit.

The price below which discharging in hour j is no longer profit maximizing is the estimate of short run marginal cost of discharging in hour j. Calculate analogously for the charging range if the expected profit maximizing dispatch in hour j is to charge. Solve problem (2) by maximizing and constraining C_j to the expected profit maximizing dispatch. The price above which charging in hour j is no longer profit maximizing (and forgoing charging becomes profit maximizing) is the estimate of short run marginal cost of foregone charging in hour j.

If π' was derived by a dispatch in the opposite direction for hour j (e.g., by charging when π^* was derived from discharging), problem (2) only needs to be solved for one value, constraining to expected maximum profit dispatch of hour j. This value will estimate marginal cost for the entire operating range of the resource because 0 MW dispatch is not considered -- it would produce less than the second best profit, and would not be profit maximizing for hour j.

If π' was derived from 0 MW dispatch in hour j, solve problem (2) up to 2 times, depending on feasible outcomes based on S_0: once constraining discharge (charge) to the expected profit maximizing level, and once constraining charge (discharge) to the maximum feasible value based on S_0[7]. The resulting two values will complete the estimated marginal cost curve for the charging and discharging ranges of the resource.

Implementation considerations

A key consideration to implementing this type of approach to estimating short run marginal cost is that it depends on a robust forecast of prices. If used as the basis for a cost-based bid in market power mitigation in the day-ahead market (i.e., a default energy bid or DEB), a forecast would be required for the entire operating day at the time the DEB is calculated. In real-time, the process could be more dynamic, perhaps incorporating more up-to-date pricing expectations as the day develops. While no forecast will be 100 percent accurate, one may reasonably expect that the battery resource operator is also dependent on a price forecast to form operating expectations in a day and to inform bidding strategy. Thus, the dependence on a forecast alone and the potential for some level of error should not be viewed as a significant point of weakness in the approach.

An additional consideration is that, for use as a DEB, state-of-charge would need to be predicted for some period in the future. For day-ahead, state-of-charge would need to be predicted and used as an input to the DEB calculation for each hour of the day. However, given a robust price forecast and an assumption on beginning state-of-charge, the expected profit maximizing dispatch (and thus state-of-charge) for each hour can be calculated as described in this document. This would serve as a reasonable assumption of state-of-charge for hours throughout the day.

In real-time, state-of-charge would need only to be estimated as far in advance of the operating hour as the DEB would be calculated. If calculated dynamically in real-time, this could be as little as two hours out. Such an estimate could rule out many possibilities of future state-of-charge based on the state-of-charge at the time of calculation and the remaining time until the operating hour. Accuracy could be improved by using an expectation of prices over the rest of the operating day that updates on an hourly basis.

A related point is that when an estimate of marginal cost is expected to be applicable to and computed for only the charge or discharge range, a DEB may still be needed for the other operating range in the event that the prediction of state-of-charge is inaccurate. In this case, the marginal cost estimate for the other operating range could be calculated with an alternate assumption of state-of-charge to serve as a backup value if needed in market power mitigation.

A final point of consideration is that a loss of precision can result when calculating the estimate of marginal cost with the assumption that the change in charge or discharge is at the maximum possible level in hour j. This can occur when the future opportunity tradeoffs required to achieve the maximum

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[7] If [7] S_0 is such that the opposite dispatch is not possible (e.g., $S_0 = 0$ so discharging is not possible), solving for the opposite operating range is not applicable and problem (2) would still be solved only one time.

dispatch in hour j occur in different hours at different prices to accommodate for roundtrip efficiency losses. If a full discharge occurs in one hour, and the charging capability for one hour is the same as discharge capability, the lost capacity from the discharge will take longer than one hour to replace. Charging will need to occur in an additional hour to account for losses. The value that results from solving problem (2) in these cases is a weighted average of the marginal costs at different output levels within the operating range. This result may be avoidable by calculating multiple different scenarios for each hour and deriving changes in marginal cost from the weighted average information. However, this may add considerably to the calculation effort involved, and the additional gains in precision may not justify the additional computational effort required.

Examples

The following examples illustrate a couple of the possible scenarios described above. These examples were set up and solved using the non-linear programming functionality of the Microsoft Excel Solver add-in.

Example 1.

$h = 4$

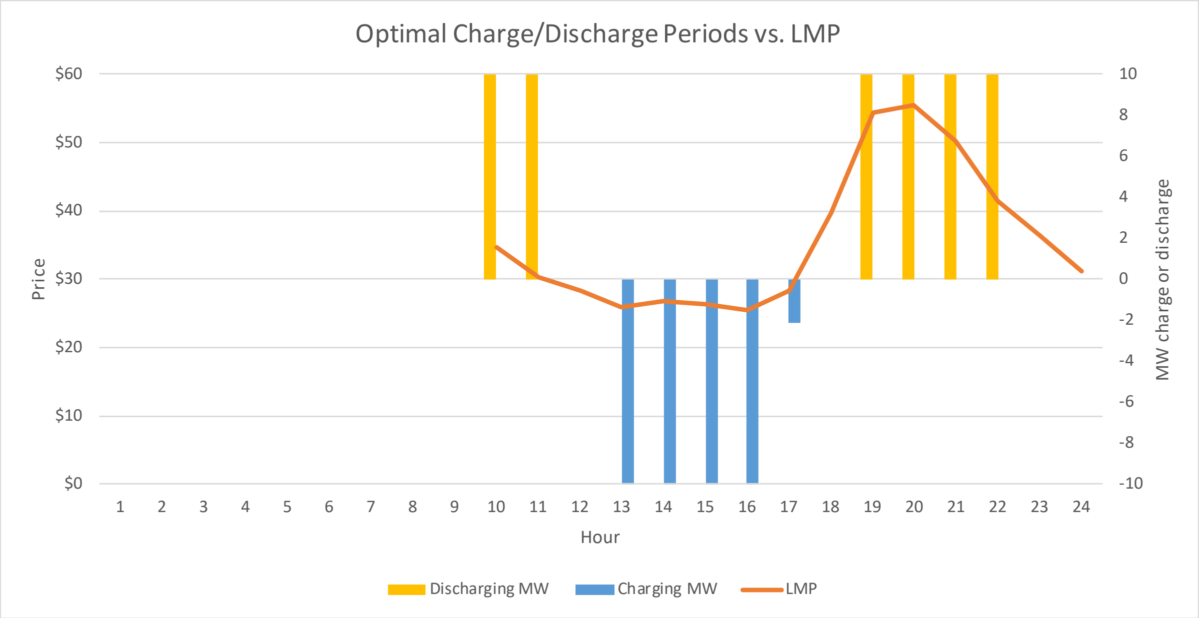
$k = l = 10$

$\eta = 0.95$

$S_0 = 20MWh$ (50%)

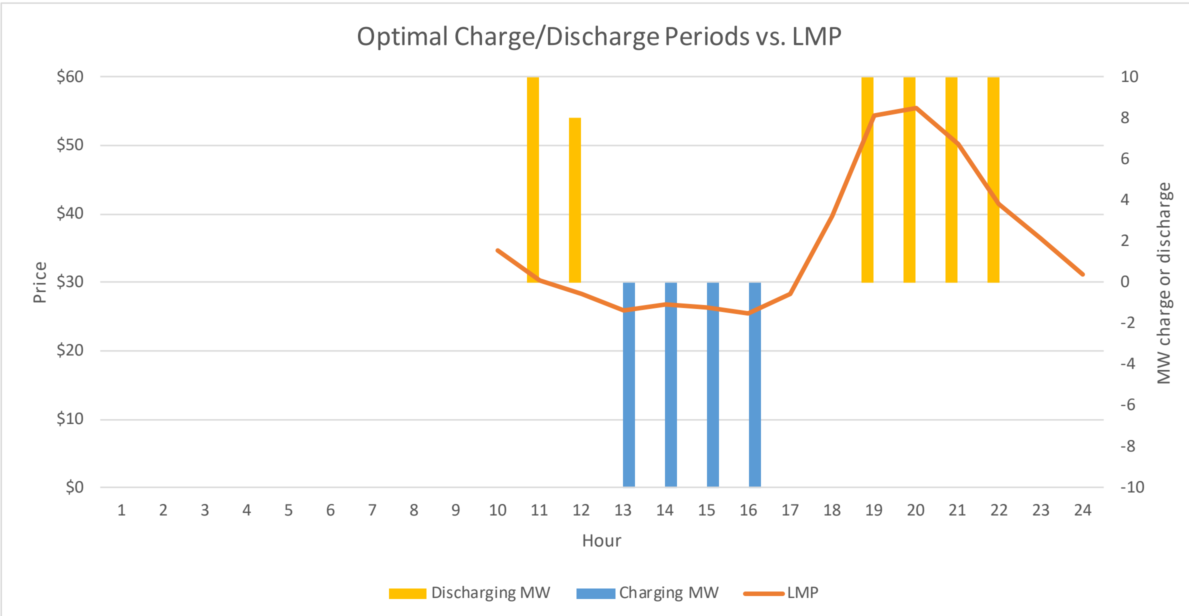
$Solving\ hour\ (j) = 10$

From problem (1): $\pi^* = \$1{,}561.257$; C_j* = 0 ; D_j* = 10



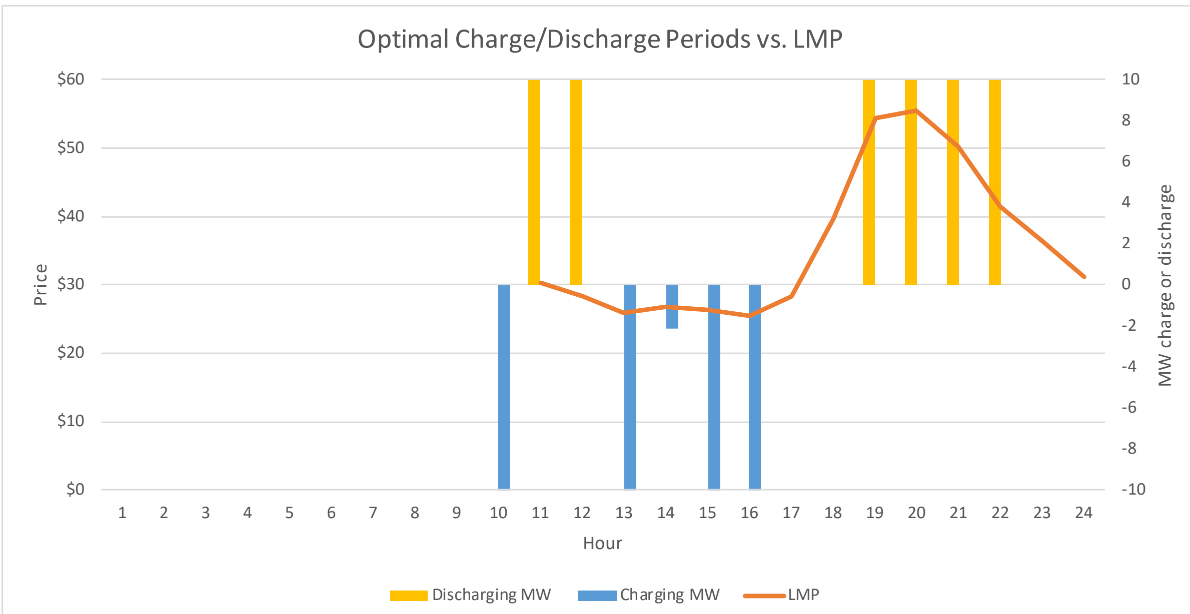
Because D_j* = 10, solve problem (1) again, constraining D_j = C_j = 0 to find second-best profit if discharge is foregone, π'. In this example, it was confirmed that the other feasible scenario of charging results in lower expected profit and is not second-best.

Solving problem (1) again with added constraint that $D_j = C_j = 0$ yields $\pi' = \$1{,}500.599$. The hypothetical dispatch that would occur under this scenario is as shown below:



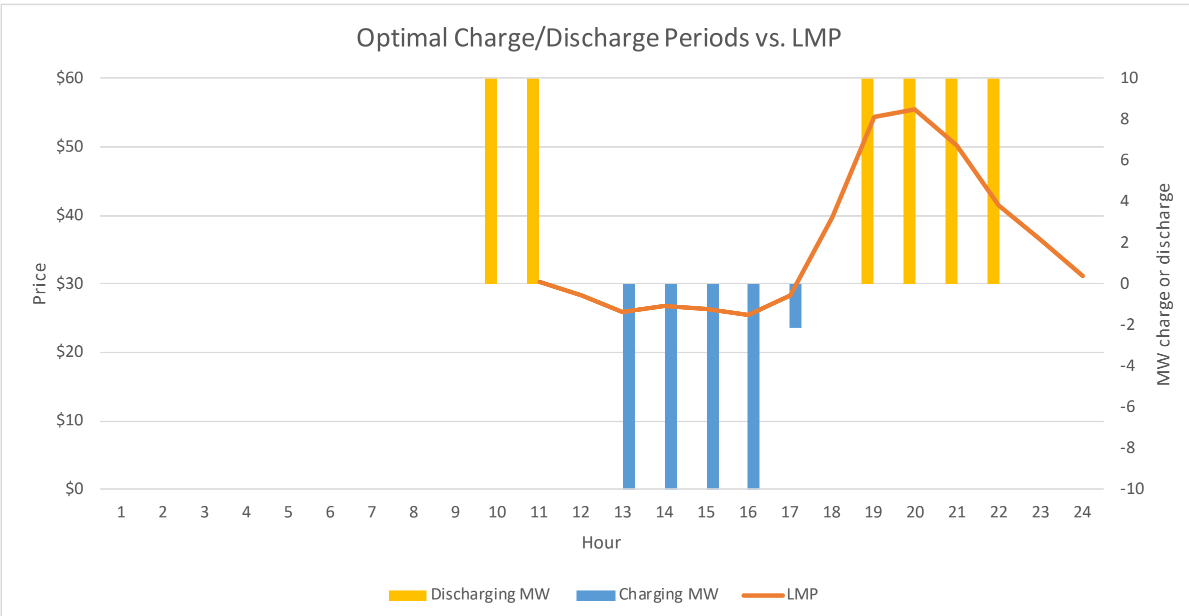
The final step is to solve problem (2) using π' as an input. Because the $S_0 = 20MWh$ (50%), both charging and discharging are possible. Further, because the second-best profit is achieved with no dispatch, problem (2) is solved twice: once for the charging range, and once for the discharging range. Based on S_0 a full charge or discharge would be possible in hour j.

For the charging range, problem (2) is maximized with C_j constrained to 10, and the resulting estimate of marginal cost for is \$26.78. Above this price, the energy storage resource will be better off forgoing charging for the second-best profit[8]. If charging were to occur below this price, the profit maximizing dispatch would be as follows:



[8] The idea here is to determine a price above which it is profit maximizing to forgo charging. Note that foregone charging has a flow impact analogous to incremental generation. The concept then is similar to finding the price above which the resource would provide generation by discharging.

For the discharging range, problem (2) is minimized with D_j constrained to 10 and the resulting estimate of marginal cost is \$28.57. Above this price, the energy storage resource will be better off discharging to exceed the second-best profit of a 0 MW dispatch. If discharging were to occur above this price, the profit maximizing dispatch would be as follows (same as the solution for π^*):



This outcome fits with the solution of π^* since the expected price in Hour 10 is \$34.64, which is above \$28.57. In other words, this dispatch remains optimal unless price is below \$28.57.

As discussed in the implementation considerations section, the result in this example is a weighted average of opportunities that are second best to discharging in hour 10. If discharging were foregone in hour 10, the resource would achieve second best profit by discharging 8 MW at the next highest price opportunity, and by retaining 2 MWh of state of charge instead of discharging and recharging in a later hour. This can be seen by comparing the above graphs for solutions of π^* vs. π'. 8 MW of discharge have an estimated marginal cost of \$28.28, the LMP in the next highest priced hour where a discharge isn't already expected (HR 12). 2 MW of discharge have an estimated marginal cost of \$28.25/0.95 = \$29.737, the LMP of the highest cost charging opportunity divided by the roundtrip efficiency loss factor—this is effectively the cost to replace the last 2 MW of discharge capacity before reaching the second peak later in the day. The weighted average .8(\$28.28) + .2(\$29.737) = \$28.57 is the calculated estimate of marginal cost by problem (2).

Example 2.

$h = 4$

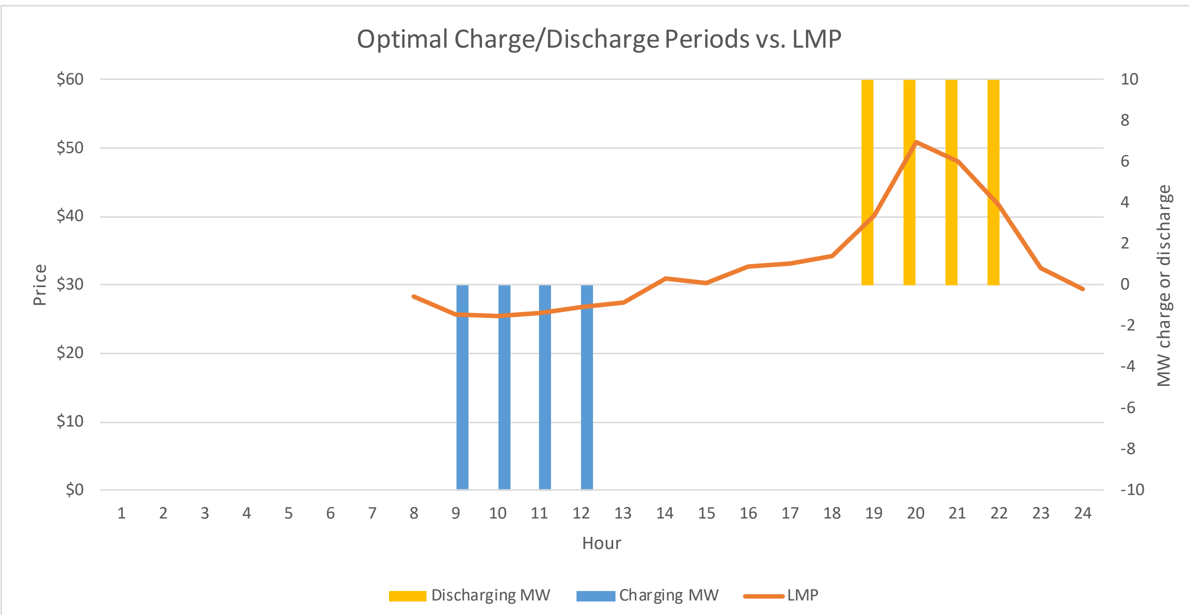
$k = l = 10$

$\eta = 0.95$

$S_0 = 2\ MWh$ (5%)

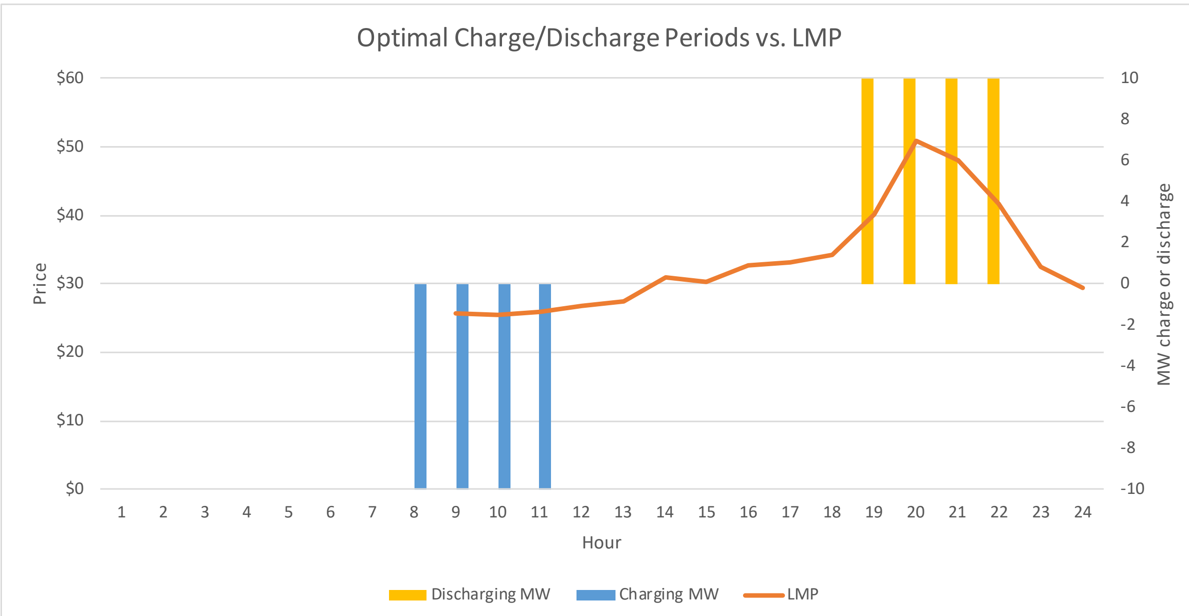
$Solving\ hour\ (j) = 8$

From problem (1): $\pi^* = \$769.008$; C_j* = 0 ; D_j* = 0



Because D_j* = C_j* = 0, there is no need to consider the second-best profit. Problem (2) can be solved using π^* as an input. The problem is solved twice since $S_0 = 2\ MWh$ (5%): once for charging at full capacity C_j = 10, and once for discharging at the maximum feasible level given S_0, D_j = 2.

For the charging range, solving problem (2) with π^* and C_j constrained to 10 yields an estimate of marginal cost at $26.85. This is just the LMP at the highest cost charging hour (Hour 12) expected to occur before reaching the profit maximizing discharge hours later in the day. This is the charging opportunity that would be given up in order to charge in Hour 8. Because of the expectation of future prices in this example, the resource should not be willing to charge at a price higher than its highest cost expected profit maximizing charging opportunity—there is no opportunity for additional profitable discharge before reaching expected profit maximizing discharge hours later in the day.



For the discharging range, solving problem (2) with π^* and D_j constrained to 2 yields an estimate of marginal cost at $28.999. This is the LMP at the lowest cost next available charging opportunity (Hour 13) expected to occur before reaching the profit maximizing discharge hours later in the day, divided by the roundtrip efficiency loss factor. At this price, the resource could discharge in Hour 8 and replace the charging energy in Hour 13 without reducing expected maximum profit over the day.