Can flexible resources be adequately compensated in low-marginal cost systems?

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Overview

Theoretical energy-only electricity markets in which all resources have convex costs are sufficient to incentivize investment in the least-cost resource mix to meet system needs. However, electricity markets have non-convex costs that preclude direct application of marginal pricing theory. For traditional thermal units, non-convex costs arise from unit commitment, startup costs, minimum operating levels, no-load costs, and non-monotonically increasing variable marginal costs. Non-convexities are also assosciacted with disallowed capacity zones in pumped hydro storage generators and more may arise as new technologies are adopted that require their own modelling approaches. Demand-response or flexible demand bids may also be most faithfully characterized with non-convexities, and such non-convex demand bids are already part of Europe's market clearing. The European electricity market requires participants to internalize their non-convex costs in complex bids that create a non-convex optimal value function from which prices must be derived. Independent system operators (ISOs) in the Untied States first solve a mixed integer program (MIP) based on submitted costs and constraints and then must assign prices based on a relaxation of this problem. In either case, the choice of relaxation to produce a quasi-marginal price, any price-adders to marginal price, and any side payments directly to market participants impacts the short-run consumer and producer surplus. The short-run price may also signal investment in different suboptimal long-run resource mixes.

As the share of variable renewable energy (VRE) grows, the amount of thermal resources – the source of most non-convexities today – is expected to decrease. However, it is unclear if the impacts of non-convexities on market outcomes will increase (because remaining thermal resources must cycle more and have steeper ramps) or decrease as the total share of energy served by thermal units decreases. Prior work [1] has raised concerns that increasing wind generation will cause flexible resources needed for system reliability to be unprofitable, but the study examines a static fleet of thermal generators that is not well-adapted to the increased wind. In this paper, we look at how different non-convex pricing models impact market outcomes in the short- and long-run as VRE increases. We examine differing levels of solar, wind, energy storage, and demand elasticity for non-adapted and well-adapted resource mixes.

Methods

We use a stylized test system of baseload, intermediate, and peaking thermal resources so that we can examine non-adapted and well-adapted systems. The centralized dispatch decision is determined by a MIP, and then a number of pricing runs are performed for each non-convex pricing model. To find a well-adapted system, we use an algorithm developed in [2] that searches nearby solution spaces for a quasi-break-even long-run solution given a pricing model. We aim to show results for both non-adapted and well-adapted resource mixes, hypothesizing that the lack of compensation for flexible units found in [1] is a result of the system being non-adapted.

We examine a number of non-convex pricing models both from the academic literature, including approximate convex hull pricing, integer programming pricing, average incremental cost pricing, and models currently utilized in U.S. ISOs, including relaxed minimum operation and partial approximate convex hull pricing.

Results

We analyze total surplus achieved and the ratio between producer and consumer surplus, compared to results for a benchmark idealized central planner. Preliminary results suggest that in the U.S.-style market, if the system is allowed to adapt in the long-run to increased wind and solar, the impact of non-convexities on market outcomes is likely to decrease. We find that long-run adapted systems to non-convex pricing models achieve excess producer surplus, but the extra profit expressed as a percentage of producer costs is relatively stable over VRE levels (i.e., shrinking shares of thermal generators in the resource mix). However, because there are fewer non-convex producers with higher shares of VRE, the absolute amount of excess producer surplus decreases. These results hold across non-convex pricing models, although different methods can result in different long-run resource mixes and different levels of transfer of consumer to producer surplus.

Conclusions

Our preliminary conclusion is that if the total market share of non-convex producers decreases in the long-run, the impact of non-convexities on market outcomes will also decrease. We emphasize the importance of considering short-run prices as signals for long-run investment decisions. As price distributions change with more low-marginal cost resources, getting non-zero prices right becomes more important. Nevertheless, we find that existing non-convex pricing models can still provide long-run cost recovery to needed flexible resources.

References

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[2] Byers, C., & Hug, G. (2021). *Long-run optimal pricing in electricity markets with non-convex costs*. http://www.optimization-online.org/DB_HTML/2021/06/8446.html