

# **Refunds of Refunds**

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The sequence of FERC decisions regarding loss surplus allocations in the PJM electricity market raises a policy question about the stability of rules and markets. Setting aside the particulars of the allocation policy and associated refunds, the subsequent order to refund refunds was without precedent. Efficient electricity markets and the benefits of virtual trading depend on the ability to rely on the rules and accept the finality of transactions. To support the important objective of market stability, there should be a high threshold for any retroactive change in policy. This high threshold has not been met in the case of the refund of refunds.

## **Introduction**

A well designed electricity market with locational energy pricing goes a long way in providing good incentives and ensuring the revenue adequacy of the system. However, some administrative allocation of residual costs and benefits is still necessary. The rules for such allocations should be both principled and predictable, at least to the extent possible. The Federal Energy Regulatory Commission (FERC) decisions on the so-called “loss surplus” refunds in the PJM electricity market presents an example where predictability is compromised. The result has been a cycle of refunds, and then refunds of refunds. Given a bad rule, it is best to change the rule going forward. But retrospective change adds costs that undermine the long-run stability and success of the market.

## **Electricity Market Design**

The central idea of efficient electricity market design is to recognize the critical characteristics of the power system, to operate that power system efficiently, and to utilize prices and associated incentives that are consistent with efficient operation under the principles of economic dispatch. (Hogan, 2002)

Prices should be set to reflect costs on the margin. If the costs are well behaved, the balance induced by the equation of price and marginal cost supports the efficient economic outcome. With the simplest representation of supply and demand, including increasing marginal costs and decreasing marginal benefits, the efficient solution establishes a welfare maximizing market equilibrium. This is what motivates economic dispatch as a core feature of the electricity market model. And this idealized model would not create residual costs.

In the presence of fixed costs, joint products, and other departures from the assumptions of the simple market structure, prices that equate marginal benefits may not cover the full costs of production. This raises the question of how to allocate costs using principles that go beyond the simplest application of the cost causation principle. In the electricity market, for example, the problem arises when there are startup costs, minimum run times and other constraints on generators which imply that the efficient, least-cost solution may not be compatible with any

given set of prices for outputs of the facility. There will be a requirement to allocate through so-called uplift charges for the costs that cannot be covered at the prices determined by the marginal costs.

An inherent feature of electricity markets is the possibility that uplift allocations can apply to benefits as well as costs. An example is the treatment of the Marginal Loss Surplus Allocation (MLSA, loss surplus) in the PJM electricity market. The MLSA arises because of a feature of electricity pricing that includes marginal losses. FERC rightly has recognized the importance of using marginal cost information, including for losses, in determining efficient electricity market prices under bid-based, security-constrained, economic dispatch.

“That is, each spot market energy customer pays an energy price that reflects the full marginal cost—including the marginal cost of transmission losses—of delivering an increment of energy to the purchaser’s location. Since losses vary in delivering energy to different locations, marginal losses increase as the number of megawatts (MW) of power moved increases.”<sup>1</sup>

A feature of this pricing methodology includes total collection for losses that is greater than the total cost of the losses. The distinction arises because of the difference in marginal and average losses. Including marginal losses in the LMP provides the right market signals, but ensures a “surplus” relative to the average cost of losses. (United States Court of Appeals for the District of Columbia Circuit, 2013) Conceptually, the resulting surplus is intimately related to the surplus in congestion costs when the transmission system is constrained. For historical reasons, however, the treatment of losses is seen differently than congestion, and market operators seek an appropriate means for allocating the loss surplus.

Both PJM and FERC have considered different means for the loss surplus allocation. A full discussion of alternative means of allocation would go beyond the scope of the present comments. Suffice it to say that the original method of allocation by actual load-ratio share for network customers was a better method than the one that was eventually applied by PJM and endorsed by FERC.

## **Day-Ahead Markets and Multi-Settlement Systems**

For a variety of reasons, the design of electricity markets includes or soon gravitates to include formal integration of forward markets that allow for advance notice for commitments, schedules and hedges. For example, a day-ahead market allows for more flexibility in planning the commitment of units and dealing with the complex dynamics of generation ramping. The analysis could include a multi-settlement system with hour-ahead, day-ahead and longer forward markets. The details are slightly different in each case, due to differences in scheduling lead times and mechanisms, but the important elements can be addressed by extending the real-time market to include a day-ahead forward market.

In essence, the day-ahead market looks similar to the real-time market. Participants make demand bids and supply offers. The system operator integrates these offers and bids with a description of the expected network conditions and determines an economic unit commitment and dispatch with associated LMPs. The participants settle for purchases and sales in the day-

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<sup>1</sup> *Black Oak Energy, LLC v. PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,042 at P 3 (2008).

ahead market at the day-ahead prices. Bilateral transmission schedules pay for the schedule at the difference in the day-ahead prices.

There are other relevant details about commitment costs and related limitations on generation. But for the present discussion an important feature of this day-ahead, market-clearing, economic dispatch is that the schedules are effectively all financial contracts. No power flows in the day-ahead market. In real-time, when actual power flows, there will be another economic dispatch based on other real-time offers and bids. Although the mechanics of accounting and settlements may be different in each case, the net result would be the same as if all the day-ahead schedules were liquidated at the real-time locational spot price, and all real-time physical transactions were settled at the respective locational spot prices. This formulation is sometimes referred to as a “gross pool.” An alternative interpretation is that the differences between the day-ahead and real-time quantities for a participant at a locational are settled at the real-time price. This is sometimes referred to as a “net pool.” Note that the settlement system characterization does not affect the dispatch or the ultimate net payments by the market participants. The economics and the aggregate financial outcome are unchanged.

This recognition that all cleared schedules in the day-ahead market are financial contracts that can be settled at real-time prices immediately opens the possibility for expanded participation. Given the uncertainty in real-time, the day-ahead contracts provide a hedge against the volatility of real-time prices. The ability to provide these hedges is not limited to those who own generation or serve load. To the extent that expected real-time prices differ from the day-ahead prices, there is an arbitrage opportunity. This arbitrage possibility creates an incentive for purely financial participants to make bids and offers for financial contracts in the day-ahead market that will be settled at real time prices. Allowing the entry of these “virtual” bids and offers, called incremental bids (INCs), decremental offers (DECs) and “Up-to-Congestion” (UTC) contract in PJM, promotes entry and the benefits of competition that come with increased liquidity. This virtual bidding promotes price discovery, allows market-based redistribution of risk, and offers an opportunity to price risk in the electricity market.

A key element of the participation of virtual traders in the day-ahead market is the increase liquidity. Since virtual traders do not need to build or control physical plant, it is relatively easy to enter the market and mitigate the potential exercise of market power or market manipulation. Combined with the role as an intermediary bridging the different interests of load and generation across a complex dynamic and spatial market, virtual traders can and do provide important contributions to a well-functioning market. Of course, the ease of entry also implies ease of exit if virtual traders face undo risks or costs.

The form of financial contract of special immediate interest for virtual trading is the UTC contract. The basic idea is to arrange a virtual schedule day-ahead between two locations with a bid for the maximum payment in the difference in the LMPs between source and destination. This is a generalization of the simple bilateral schedule with no associated bids. The UTC product allows a bid for the maximum price at which the transaction should clear. This bid allows the market participant to limit the cost that will be incurred to obtain the real-time hedge.

The UTC provides an important example of market participation by virtual traders. In addition, it took on an added role in the formulation of the loss surplus allocation. FERC and PJM made an affirmative decision to adopt a rule that included so-called “Up-To Congestion transactions.”

“Each user or customer would receive its proportionate share of the surplus based on the total MWhs of energy (a) delivered to load in PJM, (b) exported from PJM, or (c) related to cleared Up-To Congestion transactions (where the user or customer paid for transmission service). The Commission finds that PJM’s proposal is a just and reasonable method of allocating the surplus, subject to the condition that PJM clarify that its tariff complies with our finding that payments be made only to those who pay for the costs of the transmission grid.”<sup>2</sup>

Since some of the virtual transactions of day-ahead traders involved UTCs that required a payment for transmission service, this established a connection to paying for the costs of the transmission grid and the associated eligibility to receive loss surplus allocations. Therefore, the loss surplus allocation would affect the costs and benefits of virtual trading.

## **Loss Surplus Allocation and Refunds**

The controversy over the allocation of the loss surplus gave rise to a series of decisions by the FERC. The decisions were of two types. The first type concerned the particulars of the rules that should be applied to the allocation of the loss surplus. The second type addressed the period of coverage and the payment of refunds or additional charges.

The FERC order on loss surplus precipitated a complaint on December 3, 2007.<sup>3</sup> As usual, this date would serve as the anchor for notification that the rule could be revised and refunds ordered. In its decision of September 17, 2009, FERC approved the PJM compliance filing for the new method of loss surplus allocation.<sup>4</sup> The revised PJM method would apply prospectively, and was made effective as of the date of the December 2007 complaint. This decision and the merits of the particulars of the allocation method have not been taken up again by FERC, and the new loss allocation rule is not the issue at hand.

Since the new loss allocation rule was different than the prior PJM practice, the issue arose as to the application of refunds for payments that occurred since the beginning of the FERC review. The issue of refunds is complicated by the nature of PJM. For instance, PJM does not have an independent source of revenue to support refunds. Furthermore, general refund rules or changes in those rules often imply payments to one group and refunds by others. In essence, the refund decision and its period of application would necessarily involve assigning benefits to some and costs to others.

Refunds and the associated problems and impacts on participants are familiar subjects for FERC. After consideration of the refund issue, FERC made a decision to apply the refunds to cover the period since the initial launch of the review on December 3, 2007.<sup>5</sup> The Order was implemented by PJM, which paid out \$37 million in refunds to a variety of market participants.

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<sup>2</sup>       *Black Oak Energy, LLC v. PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,262 at P 23 (2009).

<sup>3</sup>       *Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.* 122 FERC ¶ 61,208, at P 46 (2008) (March 6, 2008 Complaint Order).

<sup>4</sup>       *Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,262, at P 26 (2009) (September 17, 2009 Compliance Order).

<sup>5</sup>       *Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, 131 FERC ¶ 61,024 (2010) (April 15, 2010 Rehearing Order).

While refunds are inherently an indication of a problem in market design and implementation, absent perfection they will always be a part of the nature of real electricity systems. The FERC policy decision on loss surplus allocation and the order for refunds to cover the period beginning with the formal review of the policy were both part of a familiar process with ample precedent. As part of this process, it is normal for market participants to disagree on the particulars of the rules, the need for any refunds, and the appropriate period for application of refunds. The existence of disagreement is expected, and it is FERC's role to decide.

The present case took an unusual turn when FERC took under consideration an argument from some of the market participants ("exporters") that "PJM should not be permitted to reclaim any of the credits paid to exporters of energy from PJM to the Midwest Independent Transmission System Operator, Inc. (Midwest ISO or MISO) in order to pay for the refunds to Complainants."<sup>6</sup> The exporters did not address the UTC refunds to others. Furthermore, FERC did not revisit the merits of the particular loss surplus allocation rule. Prospective application of the new rule would not be affected. Nor was the argument that the refunds had been improperly calculated, applied or paid. There was no argument about the details of implementation. Rather, the argument was simply that about the effect on the exporters to MISO.

In its decision, FERC reversed itself on the matter of the refund payments entirely, effectively ordering a refund of the refunds.<sup>7</sup> I am advised that such a refund-of-refunds decision is without precedent. There was no reconsideration of the merits of the underlying particulars of the loss allocation rule. And there was no argument that the refunds had been improperly implemented. The refund-of-refunds decision appears to rest solely on a change in FERC's view of the relative balance across the impacts on market participants.

## Prospective Rules and Market Certainty

The decision raises an important question about the nature of regulation and the impact on markets, in addition to the impacts on some market participants. It is widely recognized that among the requirements of successful markets is a degree of stability and finality in the rules and transactions. For example, in the case of contracts, I participated in earlier *Amici Brief* arguing before the Supreme Court: "Economists have long recognized that certainty of contract is essential to a healthy economy. Long-term forward contracts, in particular, help reduce financial risk. Those contracts can only accomplish that goal, however, if parties know the contracts will be enforced." (Baumol et al., 2007). FERC has long followed the principle that arm's length contracts that turn out badly for one of the parties must meet the high *Mobile Sierra* public interest standard before they can be reopened by the regulators. (Supreme Court of the United States, 2008)

While tariff rules and refund decisions are not literally the same as contracts, the analogy is apt. It will always be true that application of the contract will eventually benefit one of the parties more than the other, and there may be a desire of one side to abrogate the contract. That condition is precisely why we require judicial enforcement of contracts. Absent certainty of contracts, many of the benefits of markets, hedging, and trading would be foregone. So too with

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<sup>6</sup> *Black Oak Energy, L.L.C., EPIC Merchant Energy, L.P. and SESCO Enterprises, L.L.C. v. PJM Interconnection, L.L.C.*, 136 FERC ¶ 61,040 (2011) at P 7 (July 21, 2011 Recoupment Order).

<sup>7</sup> *Black Oak Energy, L.L.C., EPIC Merchant Energy, L.P. and SESCO Enterprises, L.L.C. v. PJM Interconnection, L.L.C.*, 136 FERC ¶ 61,040 (2011) (July 21, 2011 Recoupment Order).

market tariff rules and refunds. The rules can change prospectively with due notice, and refunds can apply with similar notice that they might be required. But once a decision is made, retrospective reversal of the decision becomes tantamount to breaking a contract.

The problem with retrospective reversals or low thresholds for reopening settled issues is not in the immediate application of a single decision. The problem arises in undermining certainty about how the market will operate. The costs to markets and market participants are real and material:

- **Higher Costs.** When uncertainty increases, the costs of doing business increase to include higher credit costs and more restrictive market exposure limits. These costs are of particular importance for virtual traders for whom credit and market risks are among the central costs they face and need to manage.
- **Lower Profits.** If revenues are subject to being clawed back retrospectively, then the putative revenues need to be discounted going forward, and higher reserves set to cover possible future repayments. Hence, the revenue expected values, and corresponding expected value of profits, are less than the nominal amounts that could always be reversed. Again this is more important for the market participants operating on the thinnest margins, which should be the case for virtual traders subject to competitive entry.
- **Restricted Markets.** A central role of a well-designed market is to allow parties to operate more efficiently by unbundling generation, transmission, distribution, and all the related supply activities needed to serve load. However, if the rules of the market increase the chances that costs and benefits of one segment or participant will be reallocated to others, there is a reduced incentive to unbundle and trade, and an increased incentive to reintegrate to internalize the uncertain transfer payments. This harms the market intermediaries, such as virtual traders as a group. It creates a barrier to entry for otherwise competitive virtual trading. This harms the market itself and works against the FERC goals of supporting competition and greater efficiency.

These impacts on markets compromise the advantage of ease of entry for virtual traders and improvement in market efficiency. The higher costs of trading will change the incentives for virtual traders who just as easily would be able to exit the market.

These costs and the arguments for greater certainty and stability transcend the particulars of any single ruling, refund or contract dispute. When there are good substantive reasons for market improvements, they should be adopted expeditiously and any necessary impacts on contracts and refunds should be order to strike a balance of costs and benefits. But retrospective reversal, after the decision is made and simply to strike a different balance of costs and benefits, should bear a strong burden of proof. The effects are not likely to be isolated to the single case at hand, but extend to a change in the perception and reality about how the market really works.

The contract analogy reminds that a contract is not sacrosanct. The same argument would apply to retrospective reversal of tariff rules or refunds. There are conditions that could justify breaking a contract, reversing the rules or refunding the refunds. However, such actions should meet a very high threshold such as defined by the *Mobile Sierra* public interest standard.

There is nothing in the present refund-of-refunds decision that has been offered that would meet this high threshold test. There is no argument about a desirable change in the basic loss surplus allocation rules. The refund choice is solely a judgment about the allocation of costs and benefits. The exporters were harmed by the original refund decision. This is not in dispute, and the fact that some are harmed is an expected feature of such refund decisions. By the same argument, other traders are harmed by the refund-of-refunds decision, and I understand that PJM may not even be able to collect the full amounts.

The implication of the refund reversal is simply that at one time FERC struck one balance for the allocation of costs and benefits of a refund decision, and later FERC changed its mind and sought to strike another balance.

There is no doubt that FERC has the responsibility for, and a good market requires, application of judgment in making such balancing decisions. However, success of the market also requires some finality in choosing such a balance and ordering refunds. The analogy to contracts applies. Once the contract is entered into in good faith, there should be a high threshold for reversing the decision. If there is a low threshold and some unhappy market participant, nothing would ever be settled. This does harm to markets. Trading costs will be higher. Expected profits will be lower and traders will reduce their market participation. In this world, the incentives would work against the broad FERC policy supporting unbundling and firms should seek the protection of reintegration to withdraw from markets and internalize as much as possible the reallocation of costs and benefits.

There is no evidence or argument even offered that anything like the required high threshold has been met here. Simple regret about past decisions should not be enough to order retrospective reversals that might be preferred by some market participants but which undermine the very foundations of the market.

The unintended consequences apply here for UTC trades, but extend to the broader principle of supporting stability in the market. The trouble now is that substantial repayments of refunds for UTC traders have already occurred, and the repayments can only be undone by yet another policy reversal. The unhappy irony is that this reversal of retrospective refunds-of-refunds is necessary to preserve the principle that such retrospective actions should bear a high burden. The repayments need to be returned in order to go back to the state after the initial refund decision.

## Conclusion

The sequence of FERC decisions on loss surplus allocation in PJM raises the issues of predictability and stability of the electricity market rules. Stability does not mean stagnation. New policies can and should be developed as a part of the process of market improvement. But stability does require a high threshold for retrospective application of new policies that have a material impact on the cost and benefits for market participants. There is nothing in the argument for the reversal of FERC's loss surplus refund decision that meets this high threshold. A return to the status as of the initial refund decision is indicated to support the large goals of the well-functioning market.

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<sup>i</sup> William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. This paper was prepared for City Power Marketing LLC, Energy Endeavors LP, Twin Cities Energy LLC, and Round Rock Energy LP. This paper draws on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, Atlantic Wind Connection, Australian Gas Light Company, Avista Corporation, Avista Utilities, Avista Energy, Barclays Bank PLC, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, California Suppliers Group, Calpine Corporation, CAM Energy, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, City Power Marketing LLC, Cobalt Capital Management LLC, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Energy, Constellation Energy Commodities Group, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Deutsche Bank Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Exelon, Financial Marketers Coalition, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL

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