ELECTRIC POWER RESEARCH INSTITUTE

Independent System Operator and Regional Transmission Organization Price Formation Working Group White Paper

Current Practice and Research Gaps in Alternative (Fast-Start) Price Formation Modeling

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ABSTRACT

The goal of the Independent System Operator/Regional Transmission Organization (ISO/RTO) Price Formation Working Group is to bring together experts in electricity market design, electricity market clearing software/algorithms, price formation, and auction design theory to collectively survey the ways in which pricing is set in electricity market clearing software. This report summarizes the discussions of this working group including a history of electricity price formation, examples that describe the basic and advanced concepts, and a summary of key challenges and gaps that can be addressed through research and development. Although actual market design evolution is driven through regulatory and stakeholder processes, the white paper can help inform ISOs/RTOs and their stakeholders on the different options that can lead to an economically efficient, reliable, and just electricity market operation.

Keywords

Electricity markets
Independent system operator (ISO)
Price formation
Regional transmission organization (RTO)

ACRONYMS

AIC	average incremental costs
CASIO	California Independent System Operator
DA	day-ahead
ELMP	extended locational marginal price
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IESO	Independent Electricity System Operator
ISO	independent system operator
ISO-NE	ISO New England
LMP	locational marginal price
MISO	Midcontinent Independent System Operator
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
Pmax	maximum capacity of a generator
PJM	PJM Interconnection
PUCT	Public Utility Commission of Texas
RT	real-time
RTO	regional transmission operator
SPP	Southwest Power Pool

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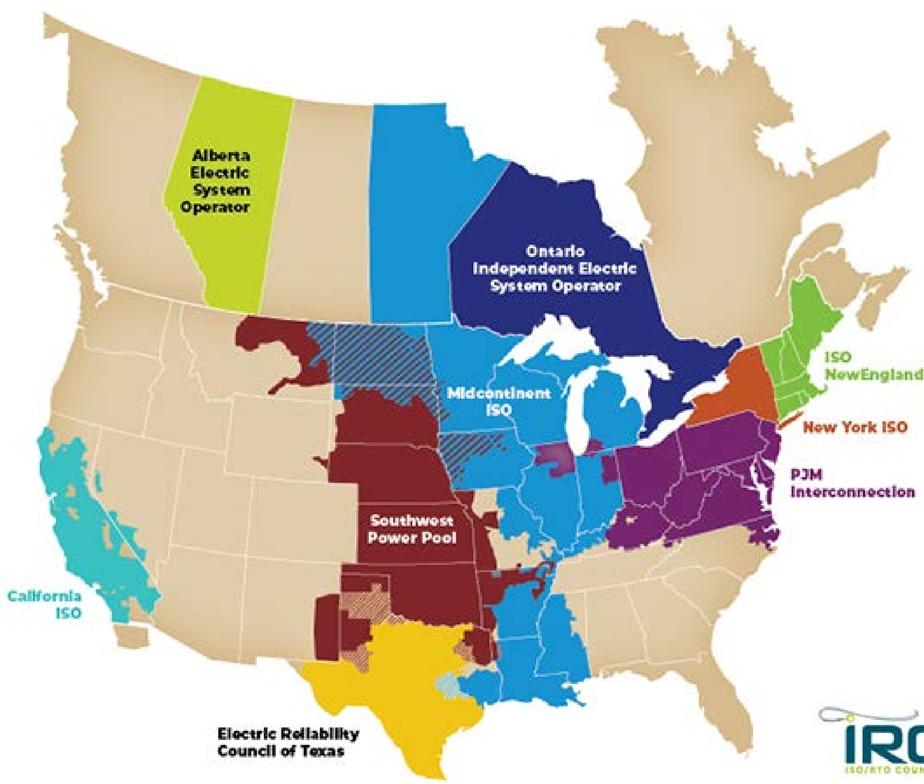
1
INTRODUCTION AND DEFINITIONS

In 2018, EPRI and the North American Independent System Operators and Regional Transmission Organizations (ISOs/RTOs), see Figure 1-1, formed the ISO/RTO Price Formation Working Group under the existing ISO/RTO Market Design Collaborative. The goal of this and the other working groups under the collaborative is to form a more specialized group of experts to discuss a topic that is of great interest to the majority of the ISOs/RTOs, provide a way to learn about the specific details of proposals or implementations and why they are designed as they are, and to find some consensus over definitions and best practices wherever applicable. One of the more significant initiatives at all the ISOs/RTOs in the last year concerns how wholesale day-ahead and real-time energy prices are calculated. This topic is often referred to as price formation. Due to recent changes in calculating prices at some ISOs/RTOs, proposed rulemakings and orders from the Federal Energy Regulatory Commission (FERC) and interest from ISOs/RTOs in understanding the history and designs in other regions, the ISO/RTO Price Formation Working Group was formed. Through collaboration with the Working Group, this paper broadly aims to summarize fundamental information and current practice on price formation, and describe ongoing research needs and gaps.



Source: ISO/RTO Council

Figure 1-1
ISO and RTO Map of North America

Paper Objectives

This paper has three main goals. First, it aims to provide detailed definitions and properties of current wholesale electricity pricing to build some consensus on terminology. This will also provide an understanding of why the discussion is important and ongoing. Second, the paper provides a high-level history of previous efforts and details the technical aspects of price formation efforts, specifically related to what is often referred to as "fast-start pricing". It will also review current practices within the ISOs/RTOs and ongoing proposals for fast-start pricing.

Third, the challenges, ongoing questions, and potential alternative market designs will be cataloged to determine potential research gaps. In the last year the Price Formation Working Group has met several times through teleconference to discuss aspects of price formation, including the definition and properties of fast-start or alternative pricing methods, examples of proposals and implementations at particular ISOs/RTOs, and advantages and disadvantages of different concepts. This goal will review and summarize the key points and discussion during those meetings and elaborate on any gaps that need further research. Through these three goals, topics which are clearly prioritized will help shape future research on price formation topics.

This paper aims to provide background information on the price formation efforts to those in the electric industry who have some background knowledge on markets but not necessarily on electricity pricing. While the paper does not provide details about electricity markets generally, we direct readers to [1] for general information, theory, and details about each ISO/RTO.

Motivation and Definitions

Price formation efforts can range from specific formulations to broad concepts. In this section, we discuss the motivation behind many price formation efforts, suggest a definition for price formation discussed within the Working Group, and additionally define the term "fast-start pricing".

Price formation has been defined broadly depending on the organization and use. The general use of the term can refer to methods for calculating prices in an industry, both from market mechanisms and other means. In the energy industry, the term has been used for many years to refer to pricing electricity products. In an extensive report on price formation [2], Susan Pope describes the problems surrounding price formation as falling into three categories: omissions and approximations in unit commitment, software difficulties including bid and offer nonconvexities, and deficiencies in product offerings and bidding rules.

In 2014, FERC initiated proceedings on price formation, defining several key topics related to pricing: use of uplift payments, offer price mitigation and offer price caps, scarcity and shortage pricing, and operator actions that affect prices [3]. From these proceedings, orders on several areas have been issued, discussed in Section 2.

Figure 1-2 presents different aspects of price formation that were categorized due to their importance, consideration and review by the ISOs/RTOs and the research community. First, nonconvex problems have been a part of electricity markets, and the operation of power systems before electricity markets. They are primarily due to the unit commitment constraints of thermal resources but are present in other aspects as well. Second, prices (along with other means like cost-recovery incentives and mandates) aim at incentivizing the attributes that are most needed to maintain system reliability in a cost-effective manner. Third, since new resources who participate in the energy market may have different types of costs and operational processes, it is important that pricing principles still apply to those resources and their costs set the price when they are marginal resources. Fourth, as ISOs/RTOs are introducing enhancements to the market clearing software that have capabilities to deliver energy to consumers at lower cost and at greater reliability, the prices that are an outcome of these enhanced software applications must ensure the price signals still incentivize resources to provide the services they may be asked to provide. Finally, as energy is interlinked with many different services that are also bought in sold through electricity markets, it is important to ensure that all prices for all products being calculated provide overall incentives for resources to do as the ISO/RTO auctions determine, without any conflicting signals.

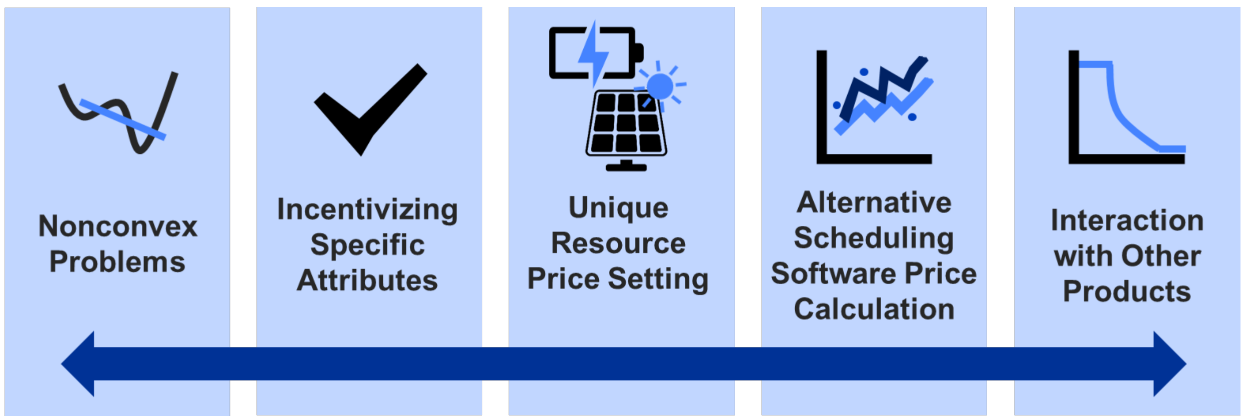


Figure 1-2
Price formation has several different sub-topics that are all important for future ISO/RTO market design. This report focuses on the first sub-topic: nonconvex problems.

To provide a general characterization of price formation and the resulting price formation efforts for electricity markets, the working group proposed the following definition.

> *Price formation is the algorithm(s) and rules that set how energy and ancillary services prices and payments are calculated in ISO/RTO wholesale electricity markets and the design of relevant settlement rules.*

The definition extends beyond the algorithms alone to include market and settlement rules. Prices and payments used in markets today are outcomes of both algorithms and rules, because electricity markets are nonconvex, out-of-market decisions are sometimes prevalent, and some services and constraints are not always within the market clearing. Side payments made to generators that ensure bid cost recovery, called uplift payments, could not be calculated without market rules or allocated to participants without settlement rules. These are key components of price formation that must be determined alongside pricing algorithms. The definition also includes both energy and ancillary services, since these are co-optimized in most markets. Defining the algorithm and rules for one will inevitably affect the other. While the working group decided to keep its focus on energy and ancillary service markets, price formation in other electricity products, like capacity markets and financial transmission rights, is important as well with several initiatives at the ISOs/RTOs over the last several years to make improvements.

The definition of price formation presented can be considered fairly broad referring to calculation and setting of prices and settlement rules that provide signals that lead to reliable and economically efficient system solutions. While all of the sub-topics shown in Figure 1-2 are of equal importance and will be touched on throughout this whitepaper given their linkages, this whitepaper is primarily focused on the first sub-topic related to non-convex problems. This issue has received the most attention in recent years, provides a starting point where the other sub-topics can be reviewed, and is also where the working group spent most of its attention on throughout the discussions over the last year.

Pricing under nonconvexity is not a new problem; it has been a topic of interest to economists and mathematicians for decades. Informally in an electricity market context, nonconvexity refers to the incorporation of costs that do not vary with output. For example, a convex market would only include costs that are variable or incremental, such as fuel costs that vary depending on the amount of production, with units in $/MWh, and no minimum generation constraints. A nonconvex market includes costs that do not change based on incremental output. For generators, these costs can include fuel needed to operate online regardless of energy production, costs incurred during startup or shutdown processes, and facility costs incurred for every hour during operation. Due to the often-cited quirks of electricity – supply must meet demand instantaneously, electricity is not storable at scale and cannot be directed, and its lack of price-responsive demand – North American electricity markets have developed in a way considering both the physical and financial side of electricity. The physical / financial market results in pricing that is not straightforward. Price formation efforts aim to 'get the right price' although there can be disagreement over what makes the price right.

Although determining prices in nonconvex markets is not a new challenge, recent changes to the electric sector have also amplified questions about pricing. Among the changes are low natural gas prices that have driven down the average cost of wholesale energy, increasing penetration of renewable generation with zero (and sometimes negative due to production-based subsidies) incremental fuel costs, increasing interest in demand-side participation, and new technologies that might require alterative market rules. These changes raise questions about the applicability of the current market designs and interactions between long- and short-run markets. These questions have been discussed at many ISOs/RTOs and will be described in greater detail in Section 4.

To provide further clarity throughout the whitepaper, there are a number of terms that require a consistent definition. These terms are defined below and their use in the remaining sections follow these definitions. While academic texts might differ on particular phraseology, these definitions attempt to clarify or reflect common terms used throughout the industry. Figure 1-3 compares several terms through example curves; each graph contains a different cost parameter on the y-axis and increasing capacity on the x-axis.

> <u>Incremental costs</u>: Costs that vary with output, in $/MWh, representing the cost of the next increment of energy at a particular operating point for a particular resource. Also referred to as variable costs or marginal costs; see definition of marginal costs. Within this paper, incremental costs specifically refer to energy costs. However, other uses of the term might also refer to reserve offer costs.

Marginal costs: Costs of a marginal resource in an auction, in \$/MWh. While sometimes used interchangeably with incremental or variable costs, incremental usually refers to the cost of next increment of a resource, while marginal refers to the cost of next increment of demand.

Average costs: Costs that vary with output, in \$/MWh, representing the total cost of the of energy divided by the production at a particular operating point. Average costs are typically not explicitly used within market clearing software.

Commitment costs: Fixed costs incurred dependent on a resource's operation, but independent of output level. Examples include no-load costs, minimum operating costs, startup costs, and shutdown costs.[1] Expressed in \$/h, \$/start, \$/shutdown. Generator bid definitions can vary between ISOs; for instance, minimum operating costs might refer to different calculations across ISOs.

Uplift payments: Out-of-market payments made to generators to ensure bid cost recovery and incentive compatibility. Uplift is a broad category of payments that includes make-whole payments and lost opportunity cost payments. Uplift payments also include payments to generators when it is turned on to relieve a non-priced constraint, e.g., voltage or stability constraints.

Opportunity cost payment: Payment resulting when a generator makes less revenue than possible if they were to maximize profit. Also referred to as a lost opportunity cost payment. There are several reasons an ISO/RTO might reimburse a resource for lost opportunity. For instance, a lost opportunity payment can result when a generator is dispatched down due to reserve that is not co-optimized with energy. In the context of nonconvex pricing, these costs can result when the price is set above a resource's incremental cost and they are not producing at their maximum output. To ensure the generator does not have an incentive to deviate from the dispatch schedule, the operator can provide this payment to the generator.

Make-whole payments: Payments resulting when a generator does not recover their bid-in costs. Since marginal cost prices (LMPs) typically reflect only incremental costs, marginal generators may not recover their commitment costs through LMP payments alone. If the generator is not able to break even over some time period (e.g., a day), they are paid a side-payment to ensure bid-cost recovery.

Production cost: Total costs resulting from short-term system operations, i.e., the total costs of producing energy for a given time period.

Capital cost: Costs needed to complete construction of a generator. Also referred to as fixed, construction or investment costs. There are many types of costs that fall into this category, which are incurred at the start of a project.

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[1] Other examples including transition costs for combined cycle gas turbines, degradation costs for energy storage resources, and ramping costs can be included in these other operating costs as well. These all may have different impacts and are less common in electricity markets today and so we primarily focus on no-load or minimum generation costs and startup costs.

Fixed costs: Costs incurred every year independent of operations. Separate from daily operation or production, there are costs that are ongoing throughout the lifetime of a plant. These are distinct from commitment costs, which are sometimes referred to as short-run fixed costs.

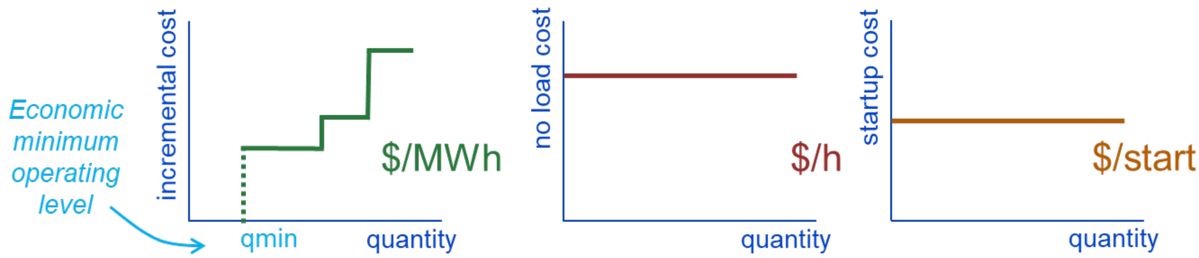

Figure 1-3
Graphical example bids for incremental or marginal costs and commitment costs (no-load and startup)

In its proceedings, FERC established the term fast-start pricing when discussing price formation efforts to refer to pricing where a subset of 'fast-start' resources may be modeled differently in market clearing processes for price-setting purposes.[2] In some ISOs/RTOs, the subset includes resources that can turn on within a certain number of minutes, while in others, it can refer to a set of block-loaded resources where their minimum and maximum capacity is equal or the difference is very small. The theory behind many implemented algorithms for alternative pricing does not include specific mention of resource type or time to startup. While reasoning has been provided in some cases, there is not necessarily a consensus or proof that the logic – explained in detail in Section 2 – can only be applied to resources that can start up fast, especially given a changing resource mix and one that differs across regions. This has led to many in the industry to ask the questions over of what the main goals are of alternative pricing in the first place.

[2] Fast-start pricing is a widely used term by FERC and ISOs/RTOs to refer to different modeling for a subset of resources during market clearing in order to set prices. In this paper, the term fast-start is used when specifically referring to a method implemented within an ISO/RTO. A more general term for pricing beyond marginal cost pricing is also used, alternative pricing, referring to any method where modeling is altered when determining prices.

2

PRICE FORMATION: KEY OBJECTIVES AND FEATURES

Price formation efforts have developed in academic literature as well as through ISO/RTO proposals. In addition to the definitions discussed in Section 1, there are objectives or aims for pricing that are essential to the financial/physical markets in North America. The first part of this section describes and defines these objectives as utilized specifically for electricity pricing. The second part of the section breaks down the components of pricing into constituent parts and uses simple examples to explain their impacts on prices. The last part of Section 2 explains the basic concepts and examples behind several common methodologies used in ISOs/RTOs.

Objectives of Electricity Pricing

There are several key principles that can help inform what leads to proper price signals. While the principles can be generalized to many industries and commodities, those listed in this section are tailored to electricity pricing. The principles are compiled from those listed in [4, 5, 6], although the list is not exhaustive. While some objectives are complementary, others can be competing or might not be simultaneously achievable. In order to establish a pricing mechanism, objectives must be prioritized.

Maximize market surplus. The primary aim of clearing a market is to maximize social welfare, also referred to as market surplus among other terms. In electricity markets, this is sometimes described as minimizing cost or least cost operations. In the day-ahead markets price-capped load and virtual supply bids can provide some demand elasticity and allow for the solver to maximize social welfare. In the real-time market few demand-side resources actively participate in the market, demand is assumed to be near perfectly inelastic and have a very high value; in this way, maximizing social welfare is equivalent to minimizing generator production costs. This principle is equivalent to ISO-NE's first principle of efficiency [5]. An efficient schedule from a cleared auction should find quantities that make participants no worse off than the next best option.

Bid-cost recovery (non-confiscation). In order to maintain a resource fleet and ensure the ISO/RTO signals are followed, a market should ensure non-confiscation, meaning entering the market auction will make participants at least the same or better off than if they did not enter the market. In other words, resources should be guaranteed to at least break even based on their bid-in costs if they follow their dispatch instructions,[3] since net revenue without market participation would be zero. If there were no operating commitment costs, this guarantee becomes less critical; however, since the marginal supplier may only make back its incremental costs, the commitment costs can be a loss for the resource. Markets today ensure net revenue is zero over some pre-

[3] In most markets, generators that deviate from their dispatch points are not guaranteed to recover their costs and may also be penalized.

defined time frame (e.g., one day). This is referred to as bid-cost recovery or a revenue sufficiency guarantee.

Incentive compatibility. This is commonly framed as ensuring truthful bidding among participants. In nonconvex markets that extend multiple time frames, identifying truthful bidding incentives can be difficult. For the purposes of this paper, we will discuss incentivizing following dispatch signals. Prices and uplift payments should incentivize resources to follow their dispatch signals. If supply resources see a price above their incremental cost, they might be inclined to increase output to 'chase' the price. However, market rules in combination with prices and uplift payments should ensure resources are incentivized to follow the dispatch setpoint sent by the operator.

Incentivizing efficient investments. In addition to short-term signals, the prices from the spot market should send signals to indicate when and where investment might be needed. These signals can indicate needs for generation as well as transmission investment, and also indicate where price-responsive demand might be needed.

Revenue neutrality. Market operators must receive or collect sufficient revenue from consumers in order to pay suppliers. In addition, they should not collect less or more than is owed since they are a neutral and nonprofit operator who does not represent either party. Market rules and pricing structures should help facilitate this balance, allowing operators to remain independent and ensure revenue adequacy and neutrality.

Transparency. Prices are published by the ISOs/RTOs and available for public use. This allows participants and potential participants to understand price characteristics, volatility and risk, and potential revenue streams. If make-whole and other uplift payments are only known to the participant who receives them, and not available to the public, some of the costs to operate the system and incentives provided to market participants are hidden from view, making it difficult for potential investors to understand future revenue streams and competitiveness of new entrants.[4] Transparency in market prices and uplift payments would allow much to be known by many, as mentioned in ISO-NE's second principle description [5].

Simplicity. Prices for electricity should send a clear signal and not need additional interpretation. As ISO-NE mentions in their third principle [5], prices should have simple logic that can be easily understood by participants. If the prices are complex or difficult to understand, they will not send clear signals and incentives to participants.

An example is useful for understanding of why the discussion of alternative pricing is occurring. The example is adapted from Stoft [6], and although it is simple, it helps explain the challenges around price transparency and investment incentives. In the example system, the capacity mix consists of 50% baseload steam turbines (ST) and 50% peaker combustion turbines (CT). Based on the demand profile, half of the year can be supplied with only the STs supplying energy. During the other half of the year, demand is higher and requires all STs and some of the CT plants to operate.

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[4] However, FERC Order 844 now requires ISO/RTOs to report total uplift costs. For instance, NYISO reports total monthly uplift and a statewide uplift rate; the monthly reports can be found at www.nyiso.com/library. While this is not a direct indication of individual or period-by-period payments, it provides more transparency on uplift.

Example 1

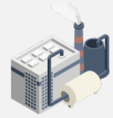
 *Steam Turbines (Baseload)*	 *Combustion Turbines (Peaker)*
50%/year serve 100% demand	50%/year needed to serve demand
Incremental Cost: $20/MWh	Incremental Cost: $40/MWh
Capital & fixed costs: *x*+$10/MWh	Capital & fixed costs: *x*
Range: 0 – maximum capacity	Range: 0 – maximum capacity
Revenue: [0.5*8760 hours*$20/MWh**P* MWh] + [0.5*8760 hours*$40/MWh**P* MWh]	**Revenue**: 0.5* 8760 hours * $40/MWh**P* MWh
Cost: 8760 hours * $20/MWh * *P* MWh	**Cost**: 8760 hours * $40/MWh * *P* MWh
Short-run profit: 0.5 * 8760 hours * $20/MWh* *P* MWh = $10/MWh	**Short-run profit**: $0/MWh

Figure 2-1
Example 1: Combustion turbines (peaker plants) are dispatchable.

In the first example, the CTs can operate anywhere between zero and maximum capacity. They set the price when they are needed, such that half of the year the price is $40/MWh and half the year the price is $20/MWh. The ST gains short-run profit as the inframarginal resources when the CTs set price, earning sufficient revenue to recover their additional fixed cost needs above those of the CTs. CTs can recover their fixed costs through a small set of the hours when there is shortage pricing or through capacity markets.

Example 2

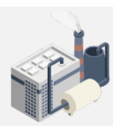
 *Steam Turbines (Baseload)*	 *Combustion Turbines (Peaker)*
50%/year serve 100% demand	50%/year needed to serve demand
Incremental Cost: $20/MWh	Incremental Cost: $40/MWh
Capital & fixed costs: x+$10/MWh	Capital & fixed costs: x
Range: 0 – maximum capacity	Range: block-loaded
Revenue: 8760 hours*$20/MWh**P* MWh	**Revenue**: 0.5*8760 hours*$20/MWh**P* MWh
Cost: 8760 hours * $20/MWh * *P* MWh	**Cost**: 8760 hours * $40/MWh * *P* MWh
Short-run profit: $0	**Short-run profit**: -$20/MWh + $20/MWh = $0

Figure 2-2
Example 2: Combustion turbines (peaker plants) are block-loaded.

In the second example, all of the CTs are block-loaded meaning they can only operate at zero or at maximum capacity. Under traditional marginal cost pricing, this means they cannot set the price and the STs set the price all year. This is because whenever a CT is turned on, at least one ST must be backed down meaning it would provide the next increment of demand and set the price. In this example, the CT is indifferent because it receives make-whole payments to recover operating costs, making its short-run profit $0. On the other hand, the ST sets the price and earns no additional revenue to recover its higher fixed annual costs. It may eventually retire.

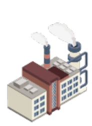
The example, while simplistic and stylized, shows how the long run equilibrium is impacted based on the characteristics of resources. Investment signals can be muted as well. For example, a new CT is considering building in the region. The owners have an improved technology compared to the existing CT where it can supply energy at $30/MWh with the same capital cost. In example 1, the technology sees the $40/MWh price and makes the decision to build to earn additional profit off the higher price. In example 2, the resource does not realize that the existing CTs cost $40/MWh and sees no incentive to build even though they are competitive.

A similar situation can result due to commitment costs. Even in example 1, if the existing CTs had commitment costs of $100/hour, they would receive the cost reimbursement for the hours they are supplying energy through make-whole payments. However, a new CT technology that costs $40/MWh with a commitment cost of $50/hour may not see the incentive to build even though it would be competitive. There is debate about the solution to these issues, but it is recognized that price signals that incentivize investments in competitive resources that can supply energy at lower cost is a desirable trait in energy price formation.

Basic Pricing Methodology Comparison

Pricing methodologies have been discussed extensively over the last decade. This section outlines the basic components or features of pricing, but does not provide a comprehensive background on all pricing methods. For further background and an overview of pricing principles and ongoing issues, see FERC’s Notice of Proposed Rulemaking on fast-start pricing [7]. Susan Pope wrote an extensive paper on price formation, including comparisons between certain ISOs/RTOs and recommendations for future efforts in [2]. A more recent comparison and update on FERC issues can be found in the R Street report in [8]. ISO-NE [5] and PJM [9] each held a series of educational seminars on price formation, which provide wide-ranging details and many example problems. Summaries of recent academic and ISO/RTO proposals can also be found in [10]. Finally, academic proposals were compared theoretically in [11], with a focus on the mathematical principles of each proposed method.

Before detailing specific methodologies, a simple example can help explain different aspects of pricing. First, features of traditional marginal cost pricing will be explained, followed by particular features or decisions that must be made before implementing alternative pricing. The simple example will demonstrate the varied prices that can occur depending on assumptions and inclusion of different components. The following basic generator characteristics are used to dispatch and price energy:



Generator Alpha

Maximum Output: 40 MW

Incremental Cost: $40/MWh

Generator Beta

Maximum Output: 100 MW

Incremental Cost: $60/MWh

When scheduling these generators for a load of 50 MW without any additional characteristics, the cheaper generator, Alpha, would be dispatched at its maximum of 40 MW and Beta would be dispatched for the remaining 10 MW to reach 50 MW of load. Since Beta would provide the next MW of demand, it would set the price at $60/MWh. There are no uplift payments required because both generators are maximizing their profits based on system conditions; Alpha makes a small profit and Beta breaks even.

With only a maximum output and incremental costs, the scheduling and pricing formulation is a simple convex problem. However, most electricity markets *commit and* schedule generators, which requires a more challenging nonconvex solution. Pricing under different assumptions is explored below, assuming none of the fast-start pricing rules in place.

Traditional Marginal Cost Pricing Features

Minimum Output

Generator Alpha

Maximum Output: 40 MW

Incremental Cost: $40/MWh

Minimum Output: 0 MW

Generator Beta

Maximum Output: 100 MW

Incremental Cost: $60/MWh

Minimum Output: 20 MW

In this example, each generator has a minimum output limit below which it cannot be dispatched. With minimum operating limits, the 40/10 MW dispatch for Alpha/Beta is not feasible given Beta's 20 MW minimum. Since both generators are needed to reach 50 MW of demand, the least cost solution has Beta dispatched at its minimum of 20 MW and Alpha would be dispatched for the remaining 30 MW. Since Alpha would provide the next MW of demand it sets the price at $40/MWh. Alpha breaks even and Beta operates at a loss. Its revenue less costs, referred to hereafter as short-run profit, is ($40/MWh - $60/MWh)*20 MW or -$400. Thus, most markets would provide Beta a make-whole payment of $400.

Commitment Costs

Generator Alpha

Maximum Output: 40 MW

Incremental Cost: $40/MWh

No-load Cost: $500

Generator Beta

Maximum Output: 100 MW

Incremental Cost: $60/MWh

No-load Cost: $500

In this example, each generator has a no-load cost that is incurred regardless of dispatch level as long as the resource is online. With no-load costs but without minimum operating limits, the schedule is Alpha dispatched to 40 MW and Beta dispatched to 10 MW. Since Beta would provide the next MW of demand it sets the price at $60/MWh which is the marginal cost to supply the next increment of supply. Due to the no-load cost, it still operates at a loss. Alpha's short-run profit is ($60/MWh - $40/MWh)*40 MW - $500, equal to $300. Beta's short-run profit is ($60/MWh - $60/MWh)*10 MW - $500, equal to -$500. Most markets would provide Beta a make-whole payment of $500.

Commitment Costs & Minimum Operating Limits

Generator Alpha

Maximum Output: 40 MW

Incremental Cost: $40/MWh

No-load Cost: $500

Minimum Output: 0 MW

Generator Beta

Maximum Output: 100 MW

Incremental Cost: $60/MWh

No-load Cost: $500

Minimum Output: 20 MW

With both no-load costs and minimum operating limits, the least cost solution is Alpha dispatched to 30 MW and Beta dispatched to 20 MW. Since Alpha would provide the next MW of demand it sets the price at $40/MWh but now both generators operate at a loss. Alpha's short-run profit is ($40/MWh - $40/MWh)*30 MW - $500, equal to -$500. Beta's short-run profit is ($40/MWh - $60/MWh)*20 MW - $500, equal to -$900. Both resources would receive make-whole payments.

This last example shows common practice for existing bidding parameters today. Generators are allowed to bid both commitment costs and minimum operating limits. Without adjustments to the pricing rules, short-run profit in the market would be -$1400. Had one of the resources also started from offline with a nonzero start-up cost, additional negative revenue would be observed, with an even greater make-whole payment required.

Fast-Start Pricing Features

Traditional marginal cost pricing, shown through examples above, sets price based on the cost of serving the next increment of demand. Mathematically, an economic dispatch problem is solved to determine prices, which takes the outcome of a unit commitment problem and fixes the binary commitment variables to their optimal solution. From the dual solution of the dispatch problem, marginal cost prices result from the shadow price of the load balance constraint.[5] It should be noted that in the alternative fast-start pricing options, commitment / dispatch and pricing are outcomes of two separate model runs. The commitment and dispatch result from a security constrained unit commitment and economic dispatch problem, which is akin to the traditional pricing method with binary commitment variables. There are many formulations for the pricing run, discussed in this section, but the dispatch resulting from these simulations is not used as a setpoint or for settlement purposes.

The examples assume both no-load costs and minimum output limits are included for resources, shown below. Some examples add additional generator characteristics.

Generator Alpha

Maximum Output: 40 MW

Incremental Cost: $40/MWh

No-load Cost: $500

Minimum Output: 0 MW

Generator Beta

Maximum Output: 100 MW

Incremental Cost: $60/MWh

No-load Cost: $500

Minimum Output: 20 MW

[5] In linear programming, for each primal (original) problem there is a dual problem. The problems can be considered complements, where with the constraints of one become variables in the other and vice versa. The dual variables, or shadow prices, reflect the value of the constraints to the objective. For instance, the dual variable for the node balance constraint (supply equals demand) is the energy price.

Minimum Output Limit Relaxation

As mentioned above, fast start pricing procedures typically require that the dispatch is determined separately from pricing. In this example, dispatch is 30 MW and 20 MW for Alpha and Beta, respectively. The price depends on how the ISO/RTO relaxes the minimum economic operating limit in the pricing simulation. If the minimum limit is relaxed to zero, the price would be set by Beta, since the dispatch result of that pricing run is 40 MW for Alpha and 10 MW for Beta. Without any additional pricing modifications, the price would be set at $60/MWh since Beta is the resource to serve the next increment of demand in the relaxed model.

However, if the ISO/RTO chooses to relax the minimum limit to some other level above zero, the price may differ. If it can only be relaxed to 90% of its minimum operating limit, Alpha would still set the price because the pricing dispatch is 32 MW for Alpha and 18 MW for Beta; Alpha can still supply the next MW of demand. In practice most ISOs/RTOs have made the decision to relax the minimum limit to zero, and the remaining examples will assume this as well.

Inclusion of Commitment Costs in Pricing

If an operator decides to include commitment costs in prices, there are two methods that have been implemented by ISOs/RTOs: Integer Relaxation and Relaxed Minimum Pricing. These methods are described in more detail in the next subsection and within the individual ISO/RTO descriptions in Section 3. In the Integer Relaxation Pricing method, the integrality constraint is relaxed for a subset of binary commitment variables, meaning that rather than a resource being on (1) or off (0), it can be anywhere in between ($0 \leq x \leq 1$). If the binary commitment variables of the problem are relaxed, the commitment costs of the marginal generator amortized over its maximum output can automatically be reflected in the price. In the Relaxed Minimum Pricing method, the amortized commitment cost must be exogenously added to a resource's incremental cost before the model is solved. In this example and with either approach, Beta's minimum output is relaxed, allowing Alpha's full capacity to be used. Beta, serving the next MW of demand, would set the price with its incremental cost and its no-load cost at $60/MWh + $500/100 MW, equal to $65/MWh.

ISOs/RTOs can also decide how to include startup costs in pricing. Some mathematical formulations will reflect startup and no-load costs in price. Most ISOs today use procedural rules to incorporate startup costs into prices.

Set of Resources Modeled Differently for Pricing

Generator Alpha

Maximum Output: 40 MW

Incremental Cost: $40/MWh

No-load Cost: $500

Minimum Output: 0 MW

Startup Time: 10 minutes

Generator Beta

Maximum Output: 100 MW

Incremental Cost: $60/MWh

No-load Cost: $500

Minimum Output: 20 MW

Startup Time: 1 hour

A key component of alternative pricing mechanisms is determining the set of resources that are modeled differently in the pricing run, including which resources have the features described in the last example applied. Meaning, the price will depend on the decision about the definition of a 'fast-start' resource. If the operator defined fast-start as those who can startup within 30 minutes and relaxed the minimum operating limit to zero, the price in this example would be the cost of Alpha because Beta is ineligible to set price in that scenario. If the definition of fast-start were an hour or less, the minimum output limit of Beta would be relaxed, and it would then set the price.

Incentive to Follow Dispatch Signals under Alternative Pricing

When pricing and dispatch are determined through separate processes, generators might not have an incentive to follow the dispatch signal. In the above example, inclusion of commitment costs in pricing resulted in a price of $65/MWh. Alpha is given a dispatch signal of 30 MW, but has a capacity of 40 MW. If Alpha acts to maximize profits, it would prefer to output 40 MW to capture additional profit. In order to prevent Alpha from producing more than 30 MW, a payment or penalty can be assigned. The payment is typically based on the opportunity cost, the potential profit Alpha could have made, which would be 10 MW * ($65/MWh - $40/MWh) or $250. Alternatively, a penalty could be imposed if the generator deviates from its dispatch signal in real-time. Both mechanisms have similar incentive structures with different advantages and disadvantages. A payment might not be revenue adequate, since there is not guaranteed to be enough excess in the market to pay the opportunity cost. A penalty might induce certain unwanted behavior from market participants who try to avoid the deviation penalty with actions such as self-scheduling, which in turn decreases the market efficiency.

Offline Resource Inclusion in Pricing

Generator Alpha

Maximum Output: 40 MW

Incremental Cost: $40/MWh

No-load Cost: $500

Minimum Output: 0 MW

Offline; Startup Time: 10 minutes

Generator Beta

Maximum Output: 100 MW

Incremental Cost: $60/MWh

No-load Cost: $500

Minimum Output: 20 MW

Online

Some pricing theories and methods include offline resources, while others only allow online resources to set prices. One pricing theory, Convex Hull Pricing, allows offline units to set the price as part of the algorithm. Practically, if the unit can startup quickly, that unit could be called upon to fill the next MW of demand. Conversely, other pricing methods limit pricing to online units; if the unit was not selected in the optimal dispatch, it should be not reflected in prices during that auction interval. In this example, if Alpha were offline but could startup within 10 minutes, an operator would need to decide if it could set the price. Otherwise, Beta would set the price during the period. Other considerations for offline units setting prices include relief of transmission or reserve shortages, where fast-start resources are only allowed to set prices only if they were needed during stressed conditions.

The resulting price from each of the features described above is compared in Table 2-1. Depending on the offer parameters and constraints that are included in the problem, prices can vary between the two generators. Separating each feature and examining the resulting price individually allows greater understanding of the impact of each characteristic independent of other model complexities.

Table 2-1
Comparison of Pricing Outcomes Considering Different Features

Features Included	Options	Price
Base (Max Cap + Incremental Costs)		$60
Base + Min Output Limit		$40
Base + Commitment Costs		$60
Base + Min Output Limit + Commitment Costs (Base UC)		$40
Base UC + Min Output Relaxation	To zero	$60
	To 90%	$40
Base UC + Inclusion of Commitment Costs + Min Output Relaxation		$65
Base UC + Resource Modeling Definition + Min Output Relaxation	≤ 10 min	$40
	≤ 1 hour	$60
Base UC + Offline Resource Inclusion	Yes	$40
	No	$60

Common Methods used in Practice at ISOs/RTOs

As discussed in the previous subsection, there are many features to consider when implementing fast-start pricing. This section will compare two common methods against a third theoretical method to show characteristics of each. The methods – Traditional Pricing, Integer Relaxation or Relaxed Minimum Pricing, and Average Incremental Cost Pricing – are compared in Figure 2-3. Traditional pricing takes the outcome of a unit commitment problem and fixes the binary commitment variables to their optimal solution. The pricing run then determines prices, which reflect marginal costs, shown in the second row of the figure. The example shown here assumes generators offer their commitment costs and submit minimum economic operating limits to the market operator.

Integer Relaxation and Relaxed Minimum Pricing refer to methods that relax the minimum output level for units modeled differently for pricing purposes. Under the most simplistic model formulation, the two methods can result in similar prices, but diverge depending on the formulation, additional constraints, and assumptions about startup cost allocation. Integer Relaxation relaxes the integrality constraint of the commitment variable between zero and one. By relaxing integrality, generation levels during the pricing run can dip below minimum operating limits and prices will incorporate the costs associated with committing the unit. ISO-NE has emphasized the importance of formulating the problem carefully because the prices that output from relaxed models can vary depending on the formulation, even if the dispatch result is the same [12].

The Relaxed Minimum Pricing method removes all commitment variables, replacing the incremental cost function of online units with one that combines incremental costs with the amortized commitment costs. Since the cost function includes commitment costs, the prices will also reflect those costs. While the approach differs, both methods produce prices that incorporate the commitment costs into the price. The no-load costs are typically amortized over the maximum capacity. Under multi-period convex hull pricing, startup costs would be allocated automatically within the pricing run; however, full multi-period pricing is not done today, and market rules are used to allocate startup costs. They are typically amortized over the maximum capacity and minimum run time, which is often one hour for fast-start resources. Under the same unit commitment solution or resource mix, prices produced are non-decreasing with increasing demand.[6]

A third method has been introduced but has not been discussed extensively within the ISOs/RTOs. The method, called Average Incremental Cost Pricing, replaces the incremental costs of resources that would otherwise receive a make-whole payment with commitment costs amortized over their dispatch [13]. The cost that is used to set the price of a marginal resource is thus equal to its average operating cost, meaning it will receive its bid-in cost to operate through uniform pricing and require no make-whole payments. Some of the mechanics are similar to the Relaxed Minimum method, but the denominator in the amortization of commitment costs is dispatch rather than maximum capacity. This produces two outcomes. First, in a single period model, there are no make-whole payments. Second, the price will be highest when a generator is at minimum load and equal to the Relaxed Minimum price at maximum load. This reflects declining costs or quantity discounts, indicating it is less expensive overall to operate at maximum compared to minimum.

The differences between the three methods are shown in set of graphs in the last row. The example shown uses the same two generators described at the beginning of the section, Alpha and Beta, including minimum operating limits and commitment costs. The examples assume both generators are considered ‘fast start’, their minimums are relaxed to zero, and their commitment costs are included in prices.

A more detailed description of the example can be found in [10]. The resulting solution can be varied across different demand levels. Between 10 and 40 MW of demand, Alpha operates alone. The Traditional price is $40/MWh, reflecting the incremental cost of the generator. The Integer Relaxation price is $52.50/MWh, or the addition of the no-load costs amortized over the maximum capacity ($40/MWh + ($500/h)/40 MW*1 h). Finally, the Average Incremental Cost price declines, from $90/MWh to $52.50/MWh at 40 MW of demand (Alpha’s maximum capacity). This reflects the declining costs to operate the unit. As demand increases, similar trends occur as Beta comes online. Note that the curves show several trends. Traditional pricing jumps between the two marginal costs, creating a nonconvex curve. Integer Relaxation is non-decreasing with demand, as demand increases, the prices stay the same or increase. Average Incremental Cost prices decrease over the course of a generator’s dispatch.

The complement of these prices is examining the second set of graphs in the figure. These show the make-whole payments owed to the generators. Traditional pricing results in either a $500 payment or higher for all levels of demand. The make-whole payment for the Integer Relaxation method decreases as demand increases, eventually becoming zero at maximum capacity. Average Incremental Cost payments remain zero for all levels of demand.

Each method finds strength in some principles discussed in Section 1 and does not fare as well with others. The differences in prices and payments emphasize the contradiction. The amount of uplift declines moving from left to right. More information about potential entry is found in the price, which some consider to be more transparent. However, moving from right to left, the incentive to deviate from dispatch decreases. This causes less need for lost opportunity cost

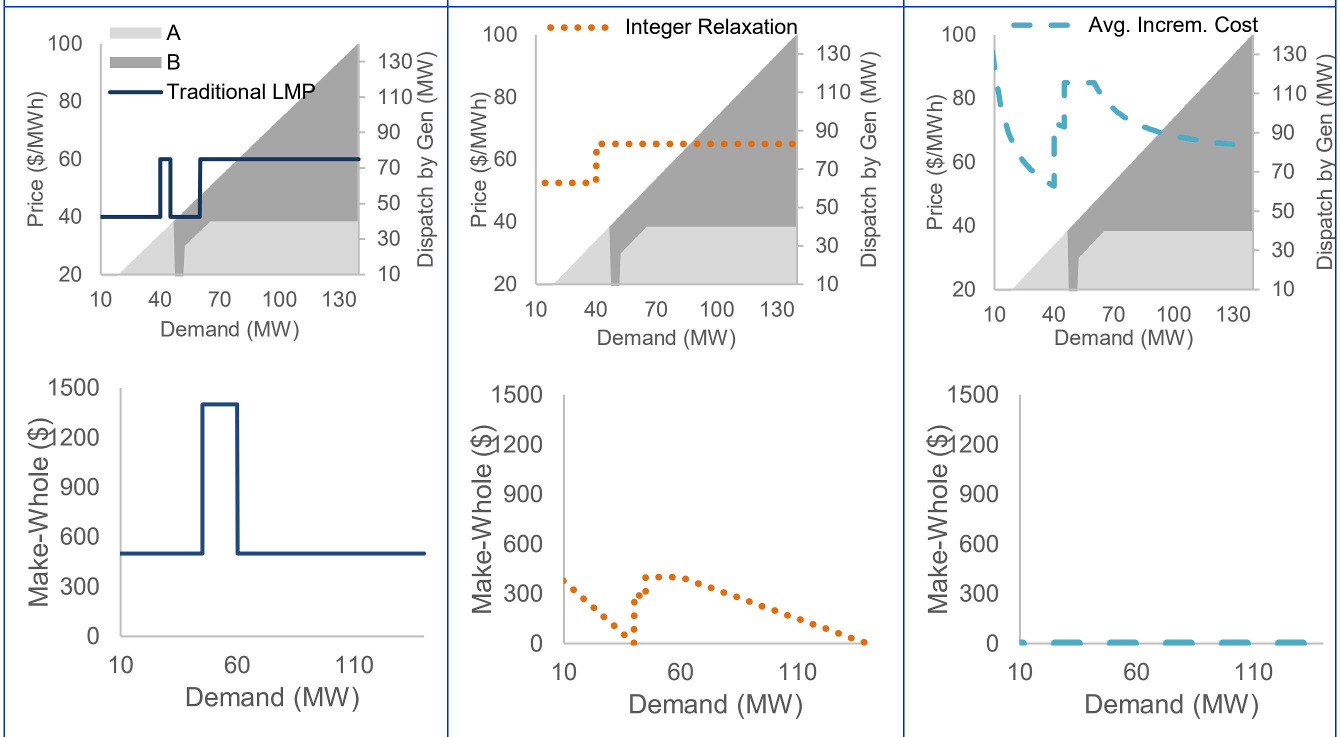
[6] Prices for the same demand level with different resource mixes (e.g., on different days) will not necessarily produce the same price.

payments or penalties. There is also reduced complexity moving right to left. The figures do not show other impacts, such as disincentivizing self scheduling out of the market, which is highest on the left with Traditional pricing. While each method can showcase some principles of pricing, no method excels in all categories. The difficulty in pricing remains that no single method dominates the others. As NYISO stated, it is "impossible to devise a rule that provides perfect incentives in all instances" [14].

The following section will provide details on implementation across the ISOs/RTOs. Most use Traditional pricing for slow-start resources and a version of Integer Relaxation for fast-start resources; however, there are many operational details that vary and can create different prices and payments.

Less Uplift / Increasing Transparency

Traditional Pricing	Integer Relaxation/ Relaxed Minimum	Average Incremental Cost
Historical way and current method for slow-start generators; the cost of meeting the next infinitesimally small increment of load	Relax the variables in pricing run to account for non-convex costs and constraints (most existing ISOs and FERC direction)	Price equal to the total cost per MWh of marginal resource. No uplift (not used in practice anywhere)
$Marginal\ Cost$	$Marginal\ Cost + \frac{No\ Load}{Max\ Cap} + \frac{Startup}{MRT * Max\ Cap}$	$Marginal\ Cost + \frac{No\ Load}{Dispatch} + \frac{Startup}{\sum_t Dispatch}$



Fewer incentives to deviate from dispatch

Figure 2-3
Comparison of sample pricing methods, including definitions, price calculations, two-generator example prices and resulting generator dispatch.

3
PRICE FORMATION IN PRACTICE

Wholesale energy market price formation has been a topic of discussion and debate since the beginning of regional markets. Each market has gone through a series of changes to its pricing calculations since beginning in the early 2000s. One of the most notable changes to pricing was the shift from zonal to nodal pricing; zonal pricing, which exists in most European markets and other markets around the world today, was composed of a single or small number of locational prices per ISO/RTO and ignored signals for congestion within these aggregate areas, rather than pricing individual nodes in the network [15].

The changes discussed in this section focus on modifications to the market clearing mechanism, rather than changes to software or policies. The second subsection describes FERC initiatives related to pricing. The third subsection details each ISO or RTO's implementation of fast-start pricing, followed by a comparison table.

Early Modifications to Pricing

New York ISO and its market participants saw potential challenges regarding traditional marginal cost pricing in order to accommodate block-loaded or fixed block units, meaning units whose minimum operating limit is equal to the maximum operating capacity. New York had about 3300 MW of these units in the New York City and Long Island area which could not set the price under traditional pricing. As described in the last section, traditional pricing is based purely on marginal cost pricing as defined through market clearing software such that the price is set to the marginal cost of meeting the next increment in demand. Because a block-loaded resource cannot ever provide the next increment of demand, it cannot set the price in the traditional pricing regime. This led to challenges with depressed prices and excess uplift payments, lack of price separation between the congested New York City area and the rest of the state, reduced incentives for demand response, and poor investment signals in the New York City area. The NYISO then implemented its hybrid dual approach. The design included the separation of multiple economic dispatch models to set prices separately from dispatch schedules. In the pricing solution, block-loaded resources had their minimum generation limits artificially relaxed to zero such that they were able to set the price, even if in the physical solution they would be blocked at their fixed level [16]. This allowed prices to be set by these resources when they were the most expensive resources being utilized. Reflecting on the first set of changes made to their rules in 2001, NYISO commented,

> "…the NYISO does not believe that this proposed hybrid pricing rule is 'perfect' in the sense that it will always result in LBMPs providing the most efficient possible incentives for every market participant. On the other hand, the operational inflexibilities associated with fixed block units **make it impossible to devise a rule that provides perfect incentives in all instances**. The NYISO has concluded that its proposed rule will work better, i.e., it will calculate LBMPs that provide efficient incentives more often and inefficient incentives less often, than any practically implementable alternative rule including the Commission's proposed rule and the NYISO's original pricing rule." [16] *emphasis added*

While some language is specific to their motion, this comment captures some of the fundamental issues with pricing. Most of the methods and rules in place today are not "perfect" and there is not a theoretically perfect solution. However, a good goal might be to ensure efficient incentives are provided more often than inefficient incentives. Although they end saying this is true in the early days of the market, the issue still persists as resource characteristics are still nonconvex.

Midcontinent ISO also began investigating modifications to pricing beginning around the mid-2000s. MISO's development was driven by several pricing issues similar to those in NYISO: certain gas turbines and Emergency Demand Response resources could not set prices. Extended LMP (ELMP) was developed based on convex hull pricing to address these issues. One of the foundational papers for their method was published in 2007 by Gribik, Hogan, and Pope, "Market-Clearing Electricity Prices and Energy Uplift." Based on the theory of convex hull, prices result in the closest market clearing prices considering lumpy costs, which minimizes the need for uplift payments. Full convex hull pricing was computationally intractable, which lead MISO to implement an approximate version they now call ELMP. After many technical workshops and a lengthy stakeholder process, MISO implemented the first phase of ELMP in 2015. Over time, the implementation has been modified in two later phases.

Figure 3-1 shows a brief timeline of price formation related activities across the ISOs/RTOs and FERC. NYISO and MISO were early movers, followed by ERCOT's implementation of increased offer caps for quick start generators. ISO-NE began an extensive series of technical seminars on price formation in 2014 as well as a project on Energy Market Offer Flexibility [17]; they implemented their version of fast-start pricing in 2017. SPP began its Price Formation Task Force in 2016. As discussed in the next subsection, FERC initiated proceedings on price formation in 2014, followed by several orders in 2016. The mechanics of each ISO's or RTO's current implementation is described later in this section.

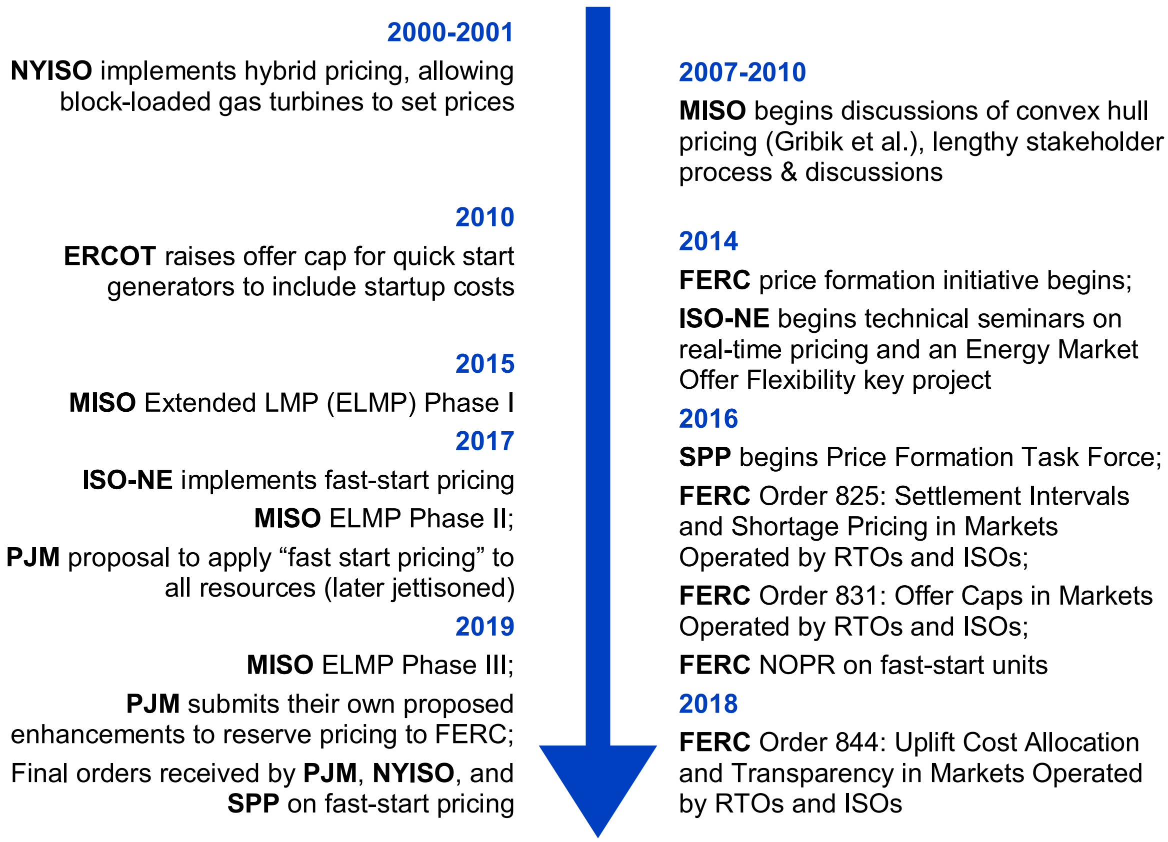


Figure 3-1
Timeline of price formation activities

FERC Initiatives and Other Filings

In 2014, FERC held workshops to discuss current practice on certain topics related to price formation. Following the conferences, FERC requested comments on the following topics that arose during discussions: offer caps, transparency, pricing with fast-start resources, settlement intervals, new products to incent flexibility, operating reserve zones, uplift allocation, market and modeling enhancements, shortage prices, transient shortage events, and interchange uncertainty. Comments and responses were submitted under Docket AD14-14-000. This range of topics is beyond the scope of this paper, but will be briefly discussed as they relate to FERC orders. FERC staff also published a series of technical papers on price formation in 2014:

"Uplift in RTO and ISO Markets PDF," Aug. 2014

"Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets PDF," Oct. 2014

"Staff Analysis of Shortage Pricing in RTO and ISO Markets PDF," Oct. 2014

"Operator-Initiated Commitments in RTO and ISO Markets PDF," Dec. 2014

Each of the papers deals with a topic that impacts pricing and helped inform the release of a few Notice of Proposed Rulemakings (NOPRs) on some of the topics. In 2016, two issues were followed by final orders: Order 825 and 831. Order 825, "Settlement Intervals and Shortage Pricing in Markets Operated by RTOs and ISOs," accomplished two price formation goals dealing with deficiencies in the way markets were settled and how shortage prices were triggered. The order requires real-time energy and ancillary service settlements to occur with the same temporal granularity, 5-minutes, that prices and schedules are calculated. The order also applies to settlements for interchange transactions, but does not apply to the settlement that load pays.[7] The order also requires that shortage pricing be triggered during any instance of shortage for energy or reserves, irrespective of the type of shortage or if the cause of the shortage is short-lived. Both rules help align pricing principles and settlements with practice, emphasizing prices should reflect actual system conditions.

FERC also released Order 831, "Offer Caps in Markets Operated by RTOs and ISOs." This allowed participants to offer costs at over $1,000/MWh as long as the offer cost is justified and capped the offer at $2,000/MWh for pricing purposes. The Order suggests that change was necessary as some resources were not previously able to include their actual costs in their short-run cost offer and were not incentivized to produce since caps were below the cost they would have incurred to procure fuel and supply energy. By allowing higher offer caps, FERC aimed to avoid price suppression and encourage all resources to submit bids and offers during all conditions.

After the two orders, FERC released a NOPR on fast start pricing [7]. In the NOPR, FERC proposed changes to price setting rules for fast-start resources, including defining a fast-start resource, allowing its commitment costs (no-load and startup) to be reflected in prices, allow its economic minimum to be relaxed, rules for offline price setting, and integration into day-ahead and real-time. After considerable comment submission, the Commission closed the docket and initiated proceedings with three system operators: NYISO, PJM, and SPP. In 2019, the three ISOs/RTOs received orders directing them to make certain modifications to current methodology, with compliance filings due later this year.

Lastly, FERC order 844, "Uplift Cost Allocation and Transparency in Markets Operated by RTOs and ISOs," established reporting requirements for uplift costs. The requirements were set up to enhance transparency and set monthly reporting per resource and on transmission constraint penalty factors, in addition to other factors.

Although not directly related to price formation, other orders and NOPRs issued by FERC can impact pricing. Order 841, "Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators," directed the ISOs/RTOs to enable storage resources to set prices when marginal resources. The pricing considerations around storage are still unfolding, as more storage comes online and participation options expand. This is similarly true for other new technologies or participants, such as distributed energy resource aggregations.

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[7] While outside FERC jurisdiction, settlement in ERCOT is on a fifteen-minute basis, although the weighting of the prices for each 5 minute interval by the Base Points of each 5 minute interval make the 15 minute settlement similar to a five-minute settlement. The two Canadian ISOs settle on an hourly basis, with prices calculated on a five-minute interval in IESO and every minute in AESO.

Current Practice

Each ISO/RTO has developed a distinct implementation of marginal cost pricing based on regional and stakeholder differences. This section outlines the implementations for each ISO/RTO as it exists in 2019. A side-by-side comparison of the implementation and market details follows the descriptions in Table 3-1. While FERC's 2016 NOPR suggested there should be features common to all pricing methods, there continues to exist regional differences and preferences that dictate how pricing has and will continue to change. The ISOs/RTOs are discussed in alphabetical order.

CAISO

Prior to California ISO's transition from zonal pricing to LMPs in 2009 and as part of the Market Redesign and Technology Upgrade, a new category of resource was introduced called "constrained output generators" (COG) [18], [19], [20]. The voluntary program is aimed at generators whose minimum economic limit is equal to its maximum limit. At the start of a year, a resource must elect to be treated as a COG resource, but resources whose minimum is equal to its maximum are not required to be treated under the pricing method [21].

In the day-ahead market, they are treated as fully dispatchable from zero to their maximum capacity. Rather than recover their hourly commitment costs through uplift, called minimum load costs[8] in CAISO, their energy offers are determined by dividing the minimum load cost by its maximum/minimum capacity. These offers are called Calculated Energy Bids. Startup costs are eligible for recovery in both day-ahead, real-time and RUC separately through make-whole payments.

In the real-time market, a COG resource is again modeled as flexible and can set the price if it is committed in the real-time unit commitment and dispatched above zero. It is considered to have an infinite ramp rate and its energy bid is also the Calculate Energy Bid. The resource is eligible for make-whole payments only if it is online due to a previous commitment and dispatched to zero in that period (not needed to meet demand).

There are no resources who have opted to be designated as COG in the CAISO markets as indicated in the CAISO response to the 2016 NOPR, as well as very few eligible resources. After the FERC NOPR was released, no further steps have been taken to incorporate characteristics of fast-start pricing mentioned in the NOPR. Unlike most other markets, CAISO has multi-interval dispatch, extending up to 13 intervals, and a flexible ramping product.

ERCOT

Unlike other U.S. ISOs/RTOs, ERCOT is not under FERC jurisdiction and subsequently was not required to respond to any Orders or NOPRs on pricing. However, they have implemented different pricing rules over time. ERCOT transitioned to nodal LMP pricing from a zonal market in December 2010, replacing Congestion Management Zones. Current implementation allows

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[8] Minimum load costs reflect costs needed to operate a generator's minimum economic operating limit (minimum load). Other ISOs/RTOs use no-load costs, which typically reflect the cost of operation independent of output, or the cost to operate at zero MW (no-load).

resources designated as Quick-Start Generating Resources to set prices based on inclusion of commitment costs.

Quick-Start Generating Resources (QSGRs) must be able to startup with ten minutes for commitment and they can also be committed through RUC. In the real-time dispatch SCED run, the minimum operating limit for QSGRs is relaxed to zero, allowing the resource the flexibility to set prices. In real-time, their offers can be mitigated to an offer cap, including no-load costs, startup costs, and fuel costs. Additionally, in real-time dispatch SCED run, the offer curve of any RUC committed resource, including QSGRs, is set to the greater of $1,500/MWh and the resource's offer. During this run, the minimum operating limit for RUC committed resources is relaxed to zero, allowing these resources the flexibility to set prices.

QSGRs are also exempt from dispatch deviation charges for the first 15 minute following a non-zero dispatch, called Resource Base Point Deviation Charges. Note that the real-time pricing run produces a system-wide price adder to the dispatch run system lambda (price), which reflects system-wide impacts but not locational impacts. Discussions in this area are ongoing with ERCOT stakeholders.

IESO

The IESO uses a "two-schedule" pricing system. It provides dispatch schedules with security-constrained economic dispatch and network constraints, but calculates prices ignoring internal network effects (unconstrained network). Resources dispatched out of merit due to congestion are made whole outside of the pricing through uplift payments that compensate for cost and lost opportunity.

Resources with start and run times over 10 minutes have their minimum operating limit relaxed to zero for the pricing run. Resources with start and run times greater than an hour also have their minimum operating limit relaxed and can set price, but must already be committed. The resulting price will only reflect the offered incremental costs. Like U.S. ISOs, generators are guaranteed cost recovery if they are dispatchable and not considered fast-start.

Resources that qualify as fast-start include all costs in their offered incremental costs; real-time does not commit units, only incremental energy, which means units offer their average costs over time. When scheduling in real-time, these resources are minimum constrained on for the purpose of dispatch. However, their minimum operating limits are relaxed to zero for the pricing run. The resulting price will reflect the no-load costs the startup costs allocated over its minimum run time. Fast-start generators are guaranteed cost recovery through the previously mentions uplift payments, that accounts for differences in constrained dispatch and unconstrained price.

Through a market renewal project, IESO is evaluating new options to update their market design. Although non-quick start resources are being committed day ahead, currently they are settled based on the real-time market prices with a cost guarantee. Under market renewal, a day-ahead market is being developed that would include both dispatch and financially binding locational marginal pricing.

ISO-NE

Through technical seminars, stakeholder processes, and tariff changes, ISO-NE has been actively involved in alternative fast-start pricing formulations [5]. LMP pricing began in 2003 at ISO-NE and implementation of the new pricing logic began in March 2017. Resources that can startup within 30-minutes can qualify for fast-start pricing in the real-time energy and reserve markets. Due to the expected smaller benefit and additional complexity, day-ahead implementation was not under consideration in the original tariff changes.

Resources that qualify as fast-start have their minimum operating limit relaxed to zero for the pricing run. The resulting price will reflect the no-load costs allocated over the maximum capacity and the startup costs allocated over its minimum run time and maximum capacity, which can be less than an hour.

ISO-NE is unique in that it pays lost opportunity costs to incentivize resources to follow their dispatch signal when backed down due to fast-start pricing. Given the higher prices produced by fast-start pricing, a resource may see a price higher than its incremental cost and want to increase their output to capture further profits. ISO-NE chose to pay lost opportunity cost, highlighting it is a stronger incentive than issuing penalties but that results in the same signal. In addition, they avoided a penalty structure because it might induce certain unwanted behavior from market participants who try to avoid the deviation penalty with actions such as self-scheduling, which in turn decreases the market efficiency [22].

MISO

MISO was the first ISO to review convex hull pricing as a possible solution and the first to implement the Integer Relaxation Pricing method. LMP pricing started in 2005 and as mentioned earlier, examinations of Extended LMP pricing began in 2007 with initial implementation in 2015 [23]. Actual convex hull pricing, or full ELMP as it is known in MISO documents, is difficult to implement due to computational intractability. As a result, MISO implemented approximate convex hull and introduced pieces of its fast-start pricing design in phases while capturing the main features of convex hull.

Phase I began with resources that could startup in 10-minutes or less with a minimum run time of 1 hour or less. The pricing run would relax the integrality constraint of these resource’s binary commitment variables between zero and one. Through this relaxation, the commitment costs would be incorporated into the price, amortized over the maximum capacity. The startup costs are amortized over the maximum capacity and the minimum run time of the unit. In the first phase, ELMP was implemented in both day-ahead and real-time, although resources committed in day-ahead were not considered eligible fast-start resources in real-time.

Any qualifying resource that was dispatched online would receive this treatment. Offline units only set the price in certain conditions, based on studying experiences of full convex hull. If they are able to relieve a transmission constraint violation or a reserve shortage condition, they can set prices. The market monitor suggested this practice would suppress prices during shortage conditions and recommended stopping the practice [24].

Phase II expanded the set of resources that could set prices in this manner, from those that could startup in 10-minutes to those with startup times of 60-minutes or less. The price impacts compared with Phase I where modest but expanding the set of resources during Phase II allowed other peaking units to set the price.

Lastly, Phase III was studied in 2019 incorporating three new elements. First, a better mathematical formulation that gets closer at full ELMP under single interval approximation was developed and prototyped in market software. The new formulation that has improved solve time significantly in day ahead SCUC may also produce full convex hull results under single interval approximation. The implementation will be deferred after the new market system is ready. Second, the independent market monitor recommended MISO allow day-ahead committed resources to be eligible to set prices as part of the real-time pricing run. MISO is targeting to implement this change in 2019. The market monitor also recommended examining ramp relaxation, since some resources with binding ramp rates might not be able to set the price. After initial studies, MISO determined further work would be needed as the solution is not straightforward given the complexity of the intertemporal constraint. Third, due to logic for regulation reserve, there were occasional day-ahead price spikes. MISO created a solution which expanded the set of resources that can be dispatched for regulation in SCED. A change was implemented in the day-ahead market in late 2017, and recently extended to real-time.

MISO continues the computational research on solving full convex hull pricing problem in day ahead [25]. There are also longer-term ELMP Phase III enhancements under exploration including the pricing for Enhanced Combined Cycle resources and the pricing under future scenarios with high penetration of renewables and emerging resources such as storage and DER. In these future scenarios with increasing importance of time-coupling ramp rate and energy limit constraints, multi-interval ELMP is investigated to price the inter-temporal costs.

NYISO

As discussed in earlier in this section, NYISO began operations using both location-based marginal pricing (NYISO's clearing price, LBMP) and an alternative pricing method for their block-loaded resources. Resources that can startup within 30-minutes, have a minimum run time of an hour, and are block-loaded qualify for NYISO's hybrid pricing methodology in day-ahead and real-time markets [26]. These resources are primarily gas turbines. Under the methodology, the minimum operating limit is relaxed to zero in the pricing pass of the solution process, allowing the resources that otherwise could not set prices to do so. Since block-loaded resources have a minimum operating limit equal to its maximum, they have no minimum load costs; their startup costs are their only commitment costs.

Under current implementation, startup costs are not included in prices, only the resource's incremental cost offers. However, startup costs are included in prices for offline combustion turbines which can startup within 10-minutes. NYISO allows these offline units to set prices since they would be able to startup quickly to solve a reliability concern. They are modeled as dispatchable between zero and maximum and with zero ramp down rate to enforce their minimum run time.

The hybrid-pricing methodology includes multiple passes in the clearing process: a physical dispatch and an economic or 'ideal' pass. The physical pass, like many other ISOs, determines the physical output signal for the fleet. The ideal pass relaxes the minimum operating limits of eligible resources, enabling fast-starting fixed block units to set prices. From the set of possible resources, eligible units in the real-time dispatch include any block-loaded unit that is committed or an uncommitted fast-start unit that can startup within 10 minutes, has a minimum run time of an hour or less, and submits offers into the energy market. The set of eligible resources can vary depending on the market (day-ahead, real-time commitment, or real-time dispatch).

After closing the fast-start pricing NOPR, FERC initiated a Section 206 investigation on price formation in the NYISO. The Final Order issued in April of 2019 requires the NYISO to update its current practices to include startup and no-load costs in prices and allow minimum operating limit relaxation for all fast-start resources, beyond block-loaded resources alone. In this way, all fast-start resources will be able to set prices. NYISO plans to implement the new fast-start pricing rules in 2020.

PJM

PJM began market operations in 1998 with LMP pricing and, similar to NYISO, has special pricing for block-loaded resources. The pricing methodology allows block-loaded units, regardless of their startup time, to set the price [27]. In the day-ahead market, there is an integrated dispatch and pricing run that incorporates logic for block-loaded resources. In the real-time market, the pricing model runs first, also incorporating the special logic, followed by the dispatch model run. The logic for block-loaded resources includes relaxing the minimum economic operating limit to 0.9 of the value, or 90% of the minimum economic limit; in 2017, the relaxation was lowered to 0.8. Because the pricing run occurs before dispatch, overgeneration can occur.

In November 2017, PJM proposed a new pricing method [28]. The method is similar to MISO, based on the Integer Relaxation pricing method. The integrality constraint of the binary commitment variables would be relaxed between zero and one in order to incorporate startup and no-load costs into prices. Unlike the other ISOs, the initial proposal recommended including all resources as part of the eligible set, rather than a subset of fast-start resources. After publication of the proposal, there was no consensus between stakeholders and other proposals are now being developed.

The proposal that PJM develops will need to address the deficiencies introduced in a FERC 206 proceeding [29]. The revisions suggest developing additional logic for fast-start resources, defined as those with a startup time of one hour and minimum run time of one hour. According to the directive, the logic should include allowing the relaxation of minimum operating limits to zero, minimizing production costs in the real-time market clearing with these resources, including commitment costs in prices, and implementing lost opportunity cost payments. PJM submitted a compliance filing to FERC, focused on improvements to their reserve markets and implementation of an operating reserve demand curve.

SPP

SPP implemented LMP pricing in 2007 and does not have extensive rules for fast-start pricing, although their rules are being updated for implementation in the near future. As of 2019, fast-start resources can register as a 'quick-start resource' with SPP if they can startup within 10-minutes. These resources are allowed to include an adder in their energy offer that includes startup and no-load costs. These additional costs might be included in price setting, depending on the submission of the resource. Block-loaded resources are not able to set prices.

The minimum operating limit of the quick-start resources is relaxed to zero during an initial screening run that occurs prior to the dispatch run. If a unit is dispatched above its minimum operating limit, it is considered online in the final run. If it is below or dispatched to zero, it is considered offline. There is no relaxation during the final dispatch run or the pricing run, which are integrated together.

Similar to NYISO and PJM, FERC proposed changes to SPP's pricing methodology in their initial announcement following the close of the fast-start pricing NOPR. The final order came out in June 2019, specifying six changes to current practice [30]. Changes include modifications to the real-time market screening run and cost amortizations, allowing the commitment costs of fast-start unit to impact prices, defining fast-start units, relaxing the minimum operating limit of fast-start units, and applying the new pricing method to registered and unregistered fast-start units. SPP is likely to create a pricing run that is separate from their dispatch run. Fast-start resources are likely to be defined as those with a startup time of less than 10 minutes and minimum run time of less than an hour. These resources will be eligible to set prices and their minimum limit will be relaxed to zero during the price run.

Table 3-1
Existing characteristics of ISO and RTO auctions and price formation efforts (Note: several ISOs/RTOs are updating practice and rules)

Characteristic	CAISO	ERCOT	IESO	ISO-NE	MISO	NYISO	PJM	SPP
Separation of scheduling and pricing	Integrated	Separate	Separate	Separate	Separate	Separate	Integrated	Integrated
Length of RT Market horizon (final dispatch)	Multiple; 13 intervals, 1-hour ahead	Single; 5-minutes ahead**	Single; 5-minute ahead	Single; 15-minute ahead	Single; 10-minutes ahead	Multiple; 5 intervals, 1-hour ahead	Single; 10-minutes ahead	Single; 5-minutes ahead
Set of resources modeled differently for pricing purposes	Online COG (block-loaded)	RUC committed resources	Block-loaded resources	30-minute and faster start-up resource	60-minute and faster start-up resources (ELMP Ph. II) includes demand response	30-minute and faster block loaded resources	Block-loaded resources	10-minute start-up, can follow dispatch
Minimum Output Relaxation	Relaxed to zero	In pricing run, relaxed to zero**	Relaxed to zero	Relaxed to zero	Relaxed to zero	Relaxed to zero	Relaxed to 80% of minimum	Relaxed for screening run, but not pricing §
Commitment Cost	Minimum generation cost allocated over Pmax	None***	Included in incremental energy cost ǂ	No-load allocated over Pmax and start-up cost allocated over Pmax and min. run time	No-load and start-up cost incorporated into price based on "unit status" relaxation	Start-up costs only included for offline 10-minute GTs	None	None §
Incentive to stay on dispatch	Proposed penalties for poor performance	Penalties for poor performance	Provision of lost opportunity cost	Provision of lost opportunity cost	Penalties for poor performance	Penalties for poor performance	ACE corrected through regulation	N/A
Offline resources			Fast-start resources		Yes, if relieving transmission/ reserve shortage condition»	Yes, 10-minute GTs only		

ERCOT: ** SCED Base Points are effective immediately upon posting and typically there is a SCED execution every 5 minutes. ERCOT also calculates and posts indicative pricing which is non-binding and provided for each 5-minute interval for 11 future intervals. Quick-start resources are relaxed to zero for dispatch (SCED). RUC committed resource offer curves are the greater of $1,500/MWh and the resource's offer.

ERCOT: *** The exception being, QSGR resources and other Resources with Voluntary Mitigation Plans (VMPs) may include startup and no-load costs or other costs in their offers. For mitigation purposes, verifiable incremental costs are used. QSGRs are allowed to include startup and no-load costs in their verifiable incremental costs. For resources with VMPs, the verifiable incremental costs are based on a filed agreement with the PUCT

IESO: [‡] Fast-start resources include commitment costs as part of their incremental energy offer.

MISO: [»] Offline resources have different criteria on startup time and are also amortized differently.

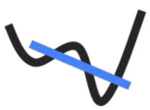
SPP: [§] Registered quick-start resources can include an adder to their energy offer with start-up and no-load costs, which is amortized over the previous year’s output, but not all quick-start resource commitment costs will set prices; minimum limits are relaxed to zero for a screening run but not the final dispatch or pricing run.

4

RESEARCH NEEDS AND GAPS

Each ISO/RTO in North America and each system operator across the globe have developed a different pricing methodology to fit the philosophy and needs of the region. Many methodologies are similar or have similar characteristics, but their differences emphasize that industry experts have not agreed on a single best methodology. This section examines the needs and gaps that have been identified by the working group, industry experts, and academics. A set of research gaps and needs is listed by the categories explained in Section 1, shown in Figure 4-1. The following subsections discuss these gaps and larger questions that remain.

Nonconvex Problems

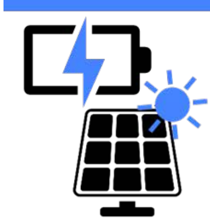


- Metrics for evaluating pricing, i.e., what makes it the “right price”, including long-run impacts and analysis of incentive compatibility (truthful bidding behavior)
- Set of resources modeled differently for pricing purposes
- Consequences of different bid structures (U.S. market three-part bids)

Incentivizing Specific Attributes

- Interaction between ramp rate constraints with and without alternative pricing
- Carbon pricing in single- and multi-state ISOs/RTOs
- Active load participation in day-ahead and real-time markets

Unique Resource Price Setting



Price setting considering:
- Systems with significant zero-cost resources (wind/ solar)
- Electric storage resources & distributed energy resources
- Extreme high-impact low-frequency events
- Non-increasing incremental costs marginal resources

Alternative Scheduling Software Price Calculation

- Evaluation of new pricing algorithms (e.g., average incremental cost pricing)
- Pricing with advanced scheduling applications (e.g., stochastic DASCUC, iDAM)
- Temporal and locational granularity for prices and settlement, e.g., multi-period settlement vs. binding-period settlement, and ex-ante vs. ex-post pricing

Interaction with Other Products

- Shortage pricing, including price levels, curve shapes (dynamic), pricing other constraint relaxations, and locational shortage
- Interaction between ramp products with and without alternative pricing
- Pricing other constraints within unit commitment

Figure 4-1
Price formation research needs and gaps

Ongoing Questions

One of the major and fundamental questions that is worth addressing has been posed by many who question changing the status quo: Is fast-start/alternative pricing necessary? Although traditional marginal cost pricing through LMPs is not a simple pricing methodology, its characteristics are established and accepted by many. Traditional prices reflect marginal costs, an essential part of any convex market. Given a clearing price, a resource can understand where they are in the supply stack based on their own incremental costs. There are no incentives to deviate from the optimal dispatch signal. There are benefits to the alternative pricing schemes, enumerated by ISOs/RTOs and others in industry that were discussed in previous sections, but the question remains: do the benefits outweigh the complexity and disadvantages?

This question is amplified when thinking about a ‘zero-marginal cost’ world dominated by renewable resources that do not have fuel costs. In a future with few thermal resources, the lumpiness of the problem will be reduced. If there were no commitment costs, the market could become convex, alleviating the need for alternative pricing. In this case, other fundamental questions arise due to the uncertainty in a 100% renewable future: Is scarcity and shortage priced appropriately? Is operator action suppressing prices when they should be high? Are offer caps too low? Some of these issues have been addressed by FERC orders and others are being tackled by ISOs/RTOs and stakeholders. One possible solution that many have considered or implemented is the use of an “operating reserve demand curve” where the current state of reliability has an impact on the current price. These questions and solutions are likely to become more important over time, regardless of the use of alternative pricing.

Throughout this paper and in most others discussing pricing, a key market element is often missing: demand. Demand-side participation in markets today is limited, and truly price responsive demand is a very small percentage of total demand. Many models and pricing formulations assume demand is perfectly inelastic. As more demand-side technologies and aggregators enter the marketplace, that assumption will need to change. Active price responsive demand has the potential to frequently set the price, especially on systems with majority zero-marginal cost resources. While price clearing methodologies do not necessarily need to change in response to demand participation, allocation of uplift costs may need to be reevaluated. Should dispatched demand pay the same share of uplift costs as forecasted demand? With increasing interest in demand management and participation, evaluating existing allocation methodologies and pricing outcomes becomes important.

Modifications to Fast-Start Pricing

Although price formation has been discussed in detail at many ISOs/RTOs and throughout the industry, some gaps remain for existing fast-start pricing methodologies. A key question all ISOs/RTOs have addressed is the set of resources that qualify for special pricing logic. Some have argued that incorporating commitment costs in prices should only apply to resources that can be called on to quickly respond, since the costs are sunk otherwise. Resources with longer start times that must be committed ahead of delivery have already incurred commitment costs ahead of the real-time market. Therefore, it is argued that those costs should not be incorporated into the price if they are the marginal unit. Others argue that commitment costs are an inherent part of the market, they make the market nonconvex; if they are used to dispatch the resources then they should also be included in prices, regardless of the unit’s startup speed. Each ISO/RTO has implemented its own set of rules. Most designate a maximum time-to-startup and minimum-run-time, while others have distinguished resources by whether the resource is block-loaded.

A significant modification to existing methods would be extending single-period market clearing to multi-period market clearing and pricing [31, 32]. Although some ISOs run multi-period models in real-time, none settle on future prices; i.e., settlement occurs for the first period and the remaining prices are non-binding and advisory. Extending markets to multi-period settlements could bring both benefits and challenges. Among the benefits is incorporating the costs of inter-temporal constraints into prices. Actions taken in the current period that impact future periods, such as dispatch points constrained by ramping limits, may not be directly reflected in all prices. Additionally, startup costs can be allocated to the period that caused the unit to start up, which might occur after actual startup. While further information about costs and constraints on the system will be reflected in prices, the difficulty in implementation is significant. In real-time, how many periods should be included? How should settlement for multiple periods occur? In addition to implementation questions, researchers must assess if the benefits justify the additional complexity.

Another significant modification would be a change to a new type of bid structure. In the U.S., generators provide a three-part bid: no-load or minimum generation costs, startup costs, and incremental energy costs. In European markets, participants can provide a single-part bid that can include aspects of their commitment costs and generator characteristics. Rather than clearing dispatch and pricing through unit commitment, where nonconvexities are internalized by the operator, some nonconvexities in European markets are internalized by the participants. The market allows more complicated bid structures, including block bids and complex orders, that can introduce binary variables when bids are either accepted in their entirety or rejected ("fill-or-kill"). Further study on the relative benefits and consequences of each pricing method could benefit new or evolving markets.

New Features or Methods

In addition to modifications to existing methods, there are new issues, technologies, and complexities that impact pricing and have been proposed for incorporation into markets. The impact of carbon or greenhouse gases has been proposed or reflected in markets in several ways. Participants bidding into CAISO's market have already incorporated a greenhouse gas adder to their bids due to California's cap-and-trade program. The adder is not an explicit price on carbon in electricity markets, as others have proposed, but an additional cost due to the compliance mandated through the state's cap-and-trade program. Challenges have arisen because although CAISO is a single state ISO, they operate a real-time Energy Imbalance Market. Participants from other states who do not have an obligation to buy carbon allowances are able to bid into the real-time markets, and prices clear reflecting participants' greenhouse gas adder. Since load outside of California should not be obligated to pay for greenhouse gas compliance mandated by another state, CAISO has implemented several updates to their pricing methodology. A key concern is ensuring prices outside the ISO do not incorporate the greenhouse gas adder, while those inside California do. Separate from any emissions trading program, NYISO and PJM have active proposals to incorporate carbon pricing into their markets. NYISO must consider seams issues as a single state ISO. PJM is a multi-state operator and must incorporate the challenge of different state policies within a single region. New formulations that include carbon pricing in market clearing will need to assess how the inclusion will inevitably impact prices.

Supply offers generally require non-decreasing bids, i.e., the first price/quantity pair must be lower than the second, which must be lower than the third, etc. However, not all generators have increasing cost functions. The nonconvexity of the markets today attests to this fact, since the submitted minimum operating limits are economic rather than physical. Some generators also have other non-increasing costs. Combined cycle generators have multiple configurations, which can lead to cost functions that do not increase with output. Many thermal resources have economic minimum limits that are different from their true (or emergency) minimum limits, often due to the fact that there is a greater incremental cost to operate below the economic minimum limit. With increasing types of resources participating in electricity markets, further evaluating non-increasing types of bids and offers would be worthwhile.

There are other reasons why price-setting may be more unique given emerging technologies. The three-part bids and incremental multi-segment cost curves that are part of today's electricity market offer paradigm are in place primarily due to the way thermal plants incur costs. Energy storage resources incur costs from the price of charging electricity in previous timeframes and from opportunity costs (hydro have similar opportunity costs). Existing designs call for these resources to offer the same multi-segment offers current resources use, where storage resources must estimate their charging and opportunity costs in every period in attempts to clear the market. Other designs in the future may be different, as ISOs/RTOs are proposing in response to FERC Order 841. For example, the ISO/RTO may elect to manage the storage resource's state of charge by using it to minimize costs without the need for an exogenous offer curve (i.e., because the costs are already determined endogenously through the model). If the resource is marginal, the price would not be based on its offer, but other factors as determined through the market clearing algorithm. Other examples of unique resources that may have different price setting logic include price-responsive demand, long-term storage (e.g., hydrogen), and independent power flow control technologies.

Similar to the importance of scarcity and shortage pricing, pricing during extreme events is likely to become more central over time. Extreme events can cause different reactions in markets. Events such as hurricanes can cause loss of load, which may not lead to a commensurate increase in prices since delivery rather than scarce supply is at issue. Events such as cold snaps can cause scarce supply, which can subsequently cause high prices. During extreme events, operators might take out-of-market actions to ensure reliability, and the cost of those actions may not always be reflected in prices. These issues suggest the need for further study. Should there be separate emergency pricing? Should there be special bidding rules during extreme events? Should out-of-market actions be priced? FERC began discussing the topic through its price formation efforts and a staff report on operator-initiated actions [33].

Evaluation Criteria

Which alternative pricing method leads to proper price signals? Answering this question requires a set of evaluation criteria for pricing, which is generally not widely agreed upon for nonconvex markets. Evaluation criteria should involve a rigorous understanding of the relationship between different pricing methods. How can two methods be compared with one another? For example, can one pricing method be the same as another under some conditions? Are prices from one method always lower than prices from another pricing method? Comparing methods can be difficult because principles of pricing often contradict each other, as noted in previous sections. Some might argue that transparency should be a key point of evaluation, while others might prefer focusing on short-term dispatch incentives. Without a consistent set of criteria that is widely agreed upon, comparing pricing methods remains difficult.

With wider adoption of different types of alternative pricing methodologies, another fundamental question arises: How can the long-term impacts of different methodologies be assessed and how do the methods impact truthful bidding behavior? The day-ahead and real-time markets send short-term signals to resources in and outside the market. The longer-term impacts are challenging to evaluate theoretically and empirically. Theoretically, a game theoretic model to assess participant behavior is difficult given the nonconvexity of the market and the multiple settlements (day-ahead and real-time). Empirically, implementation of new methods is recent and there is not a significant amount of data to use in comparison. It is also difficult to run behavioral tests on willing participants given the complexity of the market rules. While these issues are not insurmountable, investigation remains difficult.

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