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Economics of Grid-Supported Electric Power Markets: A Fundamental Reconsideration

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Boston — Delft

Foundations and Trends® in Electric Energy Systems

Published, sold and distributed by:
now Publishers Inc.
PO Box 1024
Hanover, MA 02339
United States
Tel. +1-781-985-4510
www.nowpublishers.com
sales@nowpublishers.com

Outside North America:
now Publishers Inc.
PO Box 179
2600 AD Delft
The Netherlands
Tel. +31-6-51115274

The preferred citation for this publication is

L. Tesfatsion. *Economics of Grid-Supported Electric Power Markets: A Fundamental Reconsideration*. Foundations and Trends® in Electric Energy Systems, vol. 8, no. 1, pp. 1–123, 2024.

ISBN: 978-1-63828-429-1

Foundations and Trends® in Electric Energy Systems

Volume 8, Issue 1, 2024

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Foundations and Trends® in Electric Energy Systems, 2024, Volume 8, 4 issues. ISSN paper version 2332-6557. ISSN online version 2332-6565. Also available as a combined paper and online subscription.

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Economics of Grid-Supported Electric Power Markets: A Fundamental Reconsideration

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ABSTRACT

Centrally-managed U.S. wholesale power markets operating over high-voltage AC transmission grids are transitioning from heavy reliance on fossil-fuel based power to greater reliance on renewable power with increasingly diverse suppliers and customers. This study highlights four conceptually-problematic economic presumptions reflected in the legacy core design of these markets that are hindering this transition. The key problematic presumption is the static conceptualization of the basic product as grid-delivered energy (MWh) transacted in short-run (day-ahead and intra-day) markets at competitively determined unit prices ($/MWh), conditional on delivery location and time. This study argues, to the contrary, that the basic product in need of efficient reliable transaction in these markets is reserve (physically-covered insurance) for protection against power imbalance (volumetric grid risk). This reserve is the guaranteed availability of dispatchable nodal power-production capabilities for possible central dispatch during designated future operating periods at designated grid delivery locations to satisfy

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Leigh Tesfatsion (2024), "Economics of Grid-Supported Electric Power Markets: A Fundamental Reconsideration", Foundations and Trends® in Electric Energy Systems: Vol. 8, No. 1, pp 1–123. DOI: 10.1561/3100000044.

just-in-time customer power demands and grid reliability requirements. For illustration, a recently proposed Linked Swing-Contract Market Design is briefly reviewed. The latter design permits dispatchable power resources to offer diverse types of reserve into a centrally-managed collection of linked forward bid/offer-based reserve markets via two-part pricing insurance contracts taking a flexible swing form. The swing in these contracts permits efficient planning for real-time reliability, and the two-part pricing form of these contracts permits cleared suppliers to assure their revenue sufficiency. A principled cost allocation rule supports the independence of the fiducial central manager by assuring break-even revenue adequacy for system operations as a whole.

Keywords: Market design; wholesale electric power markets; renewable power integration; volumetric grid risk; linked forward reserve markets; physically-covered insurance; flexible dispatch; nodal multi-interval pricing; revenue sufficiency; digital twinning.

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Introduction

The basic purpose of centrally-managed wholesale power markets operating over high-voltage AC transmission grids is to maintain efficient just-in-time production and transmission of bulk power to satisfy just-in-time customer power demands and grid reliability requirements.

To achieve this dynamic open-ended purpose, central managers must continually protect against *volumetric grid risk*. This physical risk is the possible disruption or collapse of grid operations due to real-time imbalance between withdrawal and/or inadvertent loss of power *from* the grid and the injection of power *into* the grid. Grid power withdrawals occur when the power usage of customers electrically connected to a grid exceeds their use of locally-generated behind-the-meter power. Inadvertent power losses occur whenever power flows across a grid's transmission lines.

In response to private economic incentives and public policy mandates encouraging grid decarbonization [21], U.S. RTO/ISO-managed wholesale power markets[1] are transitioning from a traditionally heavy

[1] Current U.S. RTO/ISO-managed wholesale power markets consist of energy, ancillary service, and capacity markets whose operations over high-voltage AC transmission grids are managed by a *Regional Transmission Organization (RTO)* or *Independent System Operator (ISO)*; see [15].

reliance on fossil-fuel based power generators to a greater reliance on *Intermittent Power Resources (IPRs)*.[2] These IPRs include wind farms, photovoltaic solar arrays, and hydropower facilities whose weather-dependent power generation is not fully firmed by storage.

The increasing participation of IPRs in U.S. RTO/ISO-managed wholesale power markets, together with initiatives such as FERC Order No. 2222 [13] encouraging more active participation by demand-side resources, has increased the uncertainty and volatility of grid *net load*.[3] In consequence, as reported in [14], RTOs/ISOs are finding it harder to procure the dependable advance availability of RTO/ISO-dispatchable power-production capabilities with sufficiently diverse attributes to maintain reliable real-time balancing of net load.[4]

Moreover, many IPRs connect to high-voltage AC transmission grids by means of power electronic inverters that convert DC to AC power, a connection technology that differs fundamentally from the traditional connection technology for fossil-fuel based power generators. At higher IPR penetration levels, this new connection technology can pose new security issues [4].

The recognition of these difficulties has led to increasingly urgent calls for action. For example, in 2021 the National Academies of Sciences (NAS) and the National Renewable Energy Laboratory (NREL) issued separate reports [35], [41] identifying key challenges facing current U.S. RTO/ISO-managed wholesale power markets. In 2022 the U.S. Federal Energy Regulatory Commission (FERC) issued an order [16] requesting a fundamental reconsideration of the design and operation of these markets. In 2024 a group of researchers at Resources for the Future (RFF) released a report [31] titled “Time for a Market Upgrade?” that

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[2]For the purposes of this study, an *Intermittent Power Resource (IPR)* is defined to be a grid-connected power resource whose power injections and/or withdrawals are not mediated through some form of aggregator and are not fully controllable by centrally-managed dispatch.

[3]The *net load* of a grid at a given point in time consists of power withdrawals and inadvertent power losses (e.g., transmission line losses) net of non-dispatched power injections.

[4]In practice, reliable real-time balancing of net load means *maintaining net-load balance within acceptable tolerance levels over time.*

examines current U.S. wholesale power market operations in relation to critical future needs.

Strongly encouraged by these calls for action, efforts are underway to improve the conceptual and operational design of U.S. wholesale power markets. As discussed in later sections of this study, these efforts are taking diverse forms. Nevertheless, they largely adhere to the following nine broadly-accepted goals:[5]

> **Goal (G1):** *Incentive Alignment.* The market design should be well-aligned with the local objectives and constraints of market participants, including privacy concerns, thus ensuring their voluntary participation.
>
> **Goal (G2):** *Resource Adequacy.* The market design should provide incentives for new resources to enter in sufficient quantity to accommodate retirements, de-ratings, and increases in power demand over time while maintaining adequate reserve to address uncertainty and volatility of net load.
>
> **Goal (G3):** *Efficiency.* The market design should be *efficient*, i.e., it should not waste resources. To promote *short-run efficiency*, the design should permit the production, transmission, and distribution of power from *existing* resources to be based on accurate assessments of benefits and costs. To promote *longer-run efficiency*, the design should encourage the development and adoption of *new* technologies permitting increased benefit from power use and reduced cost for power production and transmission.
>
> **Goal (G4):** *Reliability and Resiliency.* The market design should ensure continual net-load balancing during normal power system operations, despite weather events and other anticipated types of disturbances. The design should also support rapid recovery and return to net load balancing

[5] The specific expressions (G1)–(G8) for the first eight goals are based on Oren [37, Section II.A], Tesfatsion *et al.* [49, Section 2], and Tesfatsion [43, Section 2.2].

following sudden major disruptions, such as the loss of a line or a generation unit.

Goal (G5): *Fairness.* The market design should be *fair*, i.e., it should provide an even playing field for all actual and potential market participants. Thus, it should permit and encourage actual and potental market participants to compete for the provision of reserve and for the production, procurement, delivery, and use of electric power. It should also avoid the unintended creation of structural and strategic market advantages for some participants to the detriment of others.

Goal (G6): *Conceptual Coherency and Transparency.* The market design should be conceptually coherent, and market rules and operations under the design should be as transparent as possible.

Goal (G7): *Minimum Administrative Intervention.* The market design should discourage ad-hoc rule-making and decision-making by administrators. To further this goal, market rules and operations should be based on service requirements rather than on irrelevant physical and operational attributes of resources, to an extent compatible with the attainment of other design goals. Wherever possible, mechanisms should be instituted to permit and encourage transition to a design with limited administrative control.

Goal (G8): *Supportive of Previous Reform Efforts.* The market design should be in accordance with FERC, RTO/ISO, and stakeholder efforts to promote increased market access, pay for verified performance, demand-side participation, and encouragement of private initiative.

Goal (G9): *Internalization of Externalities.* The market design should permit the net-benefit (i.e., benefit minus cost) objective functions used in centrally-managed market-clearing processes to internalize *social* benefits and costs reflecting the environmental impacts of electric power production, transmission, and distribution.

Despite the general acceptance of goals (G1)–(G9), ongoing efforts to reform the core design of current U.S. RTO/ISO-managed wholesale power markets have been contentious. A key theme of this study is that much of this contention arises from four conceptually-problematic economic presumptions built into this core design. In brief preliminary form, these presumptions are as follows:

Problematic Presumption (P1):

The basic transacted product for grid-supported centrally-managed wholesale power markets is grid-delivered energy (MWh), i.e., accumulations of flows of power (MW) *at* designated grid locations b *during* designated operating periods T with duration measured in hours (h).

Problematic Presumption (P2):

For careful analysis of supplier revenue sufficiency in such markets, it suffices to partition total supplier cost into a "variable" component dependent on the quantity supplied and a "fixed" component independent of the quantity supplied.

Problematic Presumption (P3):

Grid-delivered energy conditional on delivery location b and delivery period T is a commodity, i.e., its units (MWh) are perfect substitutes. Thus, these units can (and should) be transacted in a spot market $M(b,T)$ at a uniform per-unit locational marginal price $\text{LMP}(b,T)$ (\$/MWh) determined in accordance with the standard competitive (marginal benefit = marginal cost) spot-pricing rule.

Problematic Presumption (P4):

The total supplier revenue attained in the spot markets in (P3) will suffice to cover total supplier cost.

Presumptions (P1)–(P4) reflect the static view that the primary role of U.S. RTOs/ISOs is to oversee the determination of unit prices

($/MWh) for grid-delivered energy (MWh) in collections of short-run competitive markets, weakly cross-correlated by needed real-time ancillary service adjustments. [6]

The current dynamic reality is far more daunting: U.S. RTOs/ISOs are fiducial conductors tasked with orchestrating the availability and possible future dispatch of increasingly-diverse dispatchable power resources to service the just-in-time power demands of increasingly diverse customers while meeting just-in-time power requirements for reliable grid operation. This orchestration is severely constrained by the physical complexity of power flows across transmission grids: a power injection anywhere flows everywhere.

Recognition of this dynamic reality results in strong counterclaims to (P1)–(P4), expressed below in brief preliminary form:

Counter-Claim (CC1):

Suppliers participating within a grid-supported centrally-managed wholesale power market provide *two* basic types of product:

Physically-Covered Insurance: *Availability* of nodal power-production capabilities for *possible* central-manager dispatch during *future* operating periods, to reduce volumetric grid risk;

Real-Time Power Delivery: *Actual delivery* of power in response to central-manager dispatch signals received *during* an operating period to satisfy just-in-time customer power demands and grid reliability requirements.

Counter-Claim (CC2):

A conceptually-sound analysis of revenue sufficiency for a supplier participating within a grid-supported centrally-managed wholesale power market requires a partitioning of this supplier's total cost

[6] The need for ancillary service adjustments, e.g., the real-time dispatch of generation capacity unencumbered by market-determined dispatch obligations, arises from inevitable discrepancies between scheduled and delivered energy, and between delivered energy and the actual flow of customer power withdrawals. These discrepancies require continual real-time corrective actions across distinct grid locations to maintain continual power balance at each of these locations.

into *three* components: (i) non-avoidable fixed cost ("sunk cost"); (ii) avoidable fixed cost; and (iii) variable cost.

Counter-Claim (CC3):

Within the context of a grid-supported centrally-managed wholesale power market, *grid-delivered energy is not a commodity.* Although grid-delivered energy has a standard unit of measurement – a megawatt-hour (MWh) – central managers and market participants do *not* consider these units to be perfect substitutes (economically equivalent) conditional on grid delivery location and time. Thus, "marginal benefit" and "marginal cost" are not well-defined concepts for grid-delivered energy.

Counter-Claim (CC4):

A grid-supported centrally-managed wholesale power market $M(T)$ for an operating period T must necessarily be a *forward* market due to the speed of real-time operations. To ensure revenue sufficiency, a supplier i participating in $M(T)$ should be permitted to submit supply offers in a *two-part pricing*[7] form enabling full compensation for:

(1) *avoidable fixed cost* that supplier i must incur to guarantee the *availability* of reserve (dispatchable nodal power-production capabilities) for possible central dispatch during T, whether or not supplier i is actually dispatched to provide power delivery during T;

(2) *variable cost* (if any) that supplier i incurs for *actual* dispatched power delivery during T.

[7]It has long been recognized by economists that two-part pricing can be used by monopolistic suppliers in *spot-market* settings as price-discrimination instruments permitting extraction of "net surplus" from buyers; see, for example, the discussion of this spot-market issue in Section 4.4. The recommended use of two-part pricing in (CC4) is for an altogether different context: namely, suppliers participating in *forward* markets might have to incur *avoidable fixed costs* to guarantee their ability to fulfill a *range* of possible real-time delivery obligations under contracts with swing (flexibility) in their delivery terms, as well as *variable costs* for actual real-time deliveries, and both types of costs must be fully covered in order for these suppliers to stay in business.

The remaining sections of this study are organized as follows. Section 2 presents a careful summary description of the *Two-Settlement System* constituting the core design feature for all seven U.S. RTO/ISO-managed wholesale power markets. Basic measurement and economic concepts essential for undertaking a fundamental reconsideration of this core design feature are reviewed in Sections 3 and 4.[8]

Section 5 highlights the dependence of the Two-Settlement System on the four economic presumptions (P1)–(P4) and carefully presents and analyzes the counterclaims (CC1)–(CC4) to these four presumptions. Section 6 then considers how the retention of the Two-Settlement System – hence presumptions (P1)–(P4) – as a core design feature is hindering the ability of U.S. RTO/ISO-managed wholesale power markets to transition smoothly to decarbonized grid operations.

Section 7 considers what else can be done. Specifically, could the Two-Settlement System be advantageously replaced by a conceptually-consistent alternative? Or, as some have argued, would the only alternative be the inefficient adoption of zonal pricing, or a return to an inefficient reliance on top-down cost-based prices set by administrators?

As a counterpoint to the latter pessimistic view, Section 7 briefly reviews an alternative *Linked Swing-Contract Market Design* [43] proposed for grid-supported centrally-managed wholesale power markets. It is argued that this alternative design is consistent with goals (G1)–(G9) and counterclaims (CC1)–(CC4), and is well-suited for the scalable support of increasingly decarbonized grid operations with more active participation by diverse suppliers and customers.

Concluding remarks are given in Section 8. Quick-reference guides for acronyms, terms, and key concepts used in this study are provided in Appendices A.1–A.5. Technical materials regarding the invertibility of demand and supply functions, used in support of counterclaims (CC1)–(CC4), are provided in Appendix A.6.

[8]Shortened versions of the essential background materials in Sections 2–4 appear in Tesfatsion [46, Sections III–IV], a companion study focused more narrowly on locational marginal pricing.

Appendices

Appendices A.1–A.6: Quick-Reference and Technical Materials

A.1 Acronyms

Acronym	Description
AC	Alternating Current
CAISO	California Independent System Operator
CFD	Contract-For-Difference
CCSM	Competitive Commodity Spot Market
CSM	Commodity Spot Market
D	Commonly used acronym for a day
DAM	Day-Ahead Market
DC	Direct Current
DM	Decision-Maker
DPR	Dispatchable Power Resource
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
h	SI metric symbol for an hour (60 s)
H	Commonly used acronym for an hour
IPR	Intermittent Power Resource
ISO	Independent System Operator
ISO-NE	Independent System Operator for New England

Continued.

A.1 Continued

Acronym	Description
kW	SI metric symbol for a kilowatt (1000 W)
kWh	SI metric symbol for a kilowatt-hour (1000 Wh)
kVA	SI metric symbol for kilovolt-Amperes (1000 Volt-Amperes)
LMP	Locational Marginal Price (or Locational Marginal Pricing)
LSE	Load-Serving Entity
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MW	SI metric symbol for a megawatt (1000 kW)
MWh	SI metric symbol for a megawatt-hour (1000 kWh)
NOPR	Notice Of Proposed Rule-making (FERC)
NYISO	Independent System Operator for New York
OOM	Out-of-Market
OPF	Optimal Power Flow
PJM	PJM Interconnection
QSE	Qualified Scheduling Entity (ERCOT)
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SI	Standard International (metric system)
SPP	Southwest Power Pool
TNS	Total Net Surplus
W	SI metric symbol for a Watt
Wh	SI metric symbol for a Watt-hour

A.2 Standard Transmission System Terms

Term	Description
Ancillary service	Service that supports system reliability
Commitment	Scheduling of a dispatchable power resource for possible future central dispatch
Dispatch	Signaling a grid-connected power resource to inject/withdraw power
Energy	Abbreviation for electric energy (MWh)
Energy loads	Devices needing a certain amount of energy over an operating-period T, but indifferent with regard to *exact* timing of this energy provision during T.
Fixed power injection	Non-dispatched must-service power injection into a grid
Fixed load	Non-dispatched must-service power withdrawal from a grid
Generation	Production of power either for local behind-the-meter use or for grid injection
Grid-delivered energy	Energy (MWh) delivered at a location via accumulation of a power-path
Intermittent power	Power injections/withdrawals not fully under central-dispatchable control
Intermittent power resource	Grid-connected non-mediated source of intermittent power
Load	Commonly-used synonym for power withdrawal from a grid; technically, a grid device or grid component to which power is delivered
Locational marginal price	Energy price conditional on delivery location and operating period
Make-whole payment	OOM compensation for a market-incurred cost
Merit-order dispatch	Dispatch in accordance with net benefit contribution
Must-service	Power withdrawal (injection) that must be balanced by power injection (withdrawal) under normal grid operating conditions
Net load	Load and inadvertent power loss minus non-dispatched power injection
Net fixed load	Fixed load minus fixed power injection
Net reserve cost	Reserve procurement cost minus reserve revenue receipts
Non-dispatchable power	Power not under RTO/ISO-dispatchable control

Continued.

A.2 Continued

Term	Description
Operating reserve	Generation capacity (MW) unencumbered by energy delivery obligations
Performance	Delivery of a good or service in response to RTO/ISO-communicated instructions
Performance cost	Variable cost incurred for providing delivery of a good or service in response to RTO/ISO-communicated instructions
Power	Abbreviation for electric power (MW)
Power absorption	Incremental down/up changes in power withdrawal offered into a power system as an ancillary service
Power imbalance	Discrepancy between grid power injection and grid power withdrawal/loss
Power injection	Insertion of power into a grid at an electrical point-of-connection
Power loads	Devices needing power at specific times to fulfill their functions or purposes
Power-path	Sequence of injections and/or withdrawals of power (MW) at a single grid location during a designated time-interval
Power-path delivery	Power-path implemented at a designated grid location during a designated time-interval in accordance with central-dispatch instructions
Power usage	Use of power as an intermediate good to further some end
Power withdrawal	Extraction of power from a grid at an electrical point-of-connection
Reserve	Service or product-provision capability that could be used to support grid reliability
Reserve bid	Contract requesting reserve availability
Reserve offer	Contract offering reserve availability
Transmission service cost	Variable cost incurred for grid operation and maintenance
Uplift payment	OOM compensation for required OOM action to maintain grid reliability

A.3 Standard Economic Terms

Term	Description
Asset	Anything of durable value, whether physical or financial
Avoidable cost	Cost that can be avoided by *not* committing to undertake a specified type of action
Avoidable fixed cost	Avoidable cost not dependent on exact form of action as long as it has specified type
Benefit (or utility) function	Function measuring the increase in own-welfare attained by a customer from the consumption and/or use of goods and/or services
Commodity	Asset Q with a standard unit of measurement u such that, at any given location and time, Q-traders consider all available Q-units u to be perfect substitutes
Competitive market	Commodity market whose buyers and suppliers are price-takers
Competitive equilibrium	Competitive market price-quantity outcome s.t. aggregate demand = aggregate supply
Consumer	Purchaser of goods/services for direct own consumption/use (no resale)
Contract in firm form	Non-contingent contract whose terms are binding on all parties
Contract in option form	Holder has the right, but not the obligation, to exercise the contract
Customer	Purchaser of goods/services either for direct own consumption/use or for resale
Demand schedule (inverse)	Schedule expressing the maximum Q-unit price a buyer is willing to pay for each additionally demanded unit of a commodity Q
Demand schedule (ordinary)	Schedule expressing the maximum amount of a commodity Q that a buyer is willing to purchase at each successively higher Q-unit price
Efficiency	No wastage of resources
Fixed cost	Cost not dependent on a specific form of action undertaken
Forward market	Transacted amounts and payment obligations for these transacted amounts *occur in advance* of the delivery of these transacted amounts
Futures market	Forward market for a commodity
Good	Exchangeable physical item whose acquisition provides benefit to the procurer

Continued.

A.3 Continued

Term	Description
Hedonic pricing	Pricing of a product by means of prices separately assigned to its intrinsic physical attributes and/or its external circumstances
Joint products	Products jointly produced from a given set of inputs
Law of One Price	In the absence of trade frictions (e.g., differences in trade locations, trade times, and/or trader product information), trader exploitation of arbitrage opportunities will ensure that every unit of a commodity available for purchase (sale) has the same purchase (sale) price.
Marked efficiency	No wastage of opportunity to increase total net surplus for buyer and supplier participants
Net benefit	Benefit minus avoidable cost
Net buyer surplus	Difference between the *maximum payment* a buyer *is willing to make* to purchase an item z and the *actual payment* the buyer makes to purchase z
Net supplier surplus	Difference between the *actual payment* a supplier *receives* for the sale of an item z and the *minimum payment* the supplier *is willing to receive* for the sale of z
Opportunity cost	Earnings foregone by not committing assets to an alternative next-best use
Pareto efficiency	No wastage of opportunity to increase benefit for some at no cost to others by means of a feasible reallocation of resources
Perfect substitutes	Two items are *perfect substitutes* (or *economically equivalent*) for a trader at a given location and time if substitution of either item for the other item does not affect the trader's economic valuation of this item.
Price-taker	Trader participating in a market for a good or service who behaves as if his own market transactions cannot affect the market price of this good or service.
Product	Outcome of a production process
Production process	Process that transforms inputs into one or more outputs
Productive efficiency	No physical wastage of production inputs and/or production outputs
Purchase reservation value	Maximum payment a buyer is willing to make to procure a designated item

Continued.

A.3 Continued

Term	Description
Revenue sufficiency	Supplier revenue is sufficient to cover supplier avoidable cost
Risk	Possibility of an adverse deviation from an expected outcome
Risk aversion	Unwillingness to participate in a risky undertaking with zero expected payoff
Sale reservation value	Minimum payment a supplier is willing to accept to supply a designated item
Service	Action taken by an entity that provides benefit to another entity
Spot market	Transacted amounts, payments for these transacted amounts, and deliveries of these transacted amounts *all occur at the same location and time* ("on the spot").
Strategic market advantage	Unintended opportunity for a participant to exploit market rules to gain advantage.
Structural market advantage	Instituted market feature that systematically favors some participants over others
Sunk cost	Non-avoidable fixed cost
Supply offer	Offer to provide an item or service
Supply schedule (inverse)	Schedule expressing the minimum Q-unit price a supplier is willing to accept in payment for each additionally supplied unit of a commodity Q
Supply schedule (ordinary)	Schedule expressing the maximum amount of a commodity Q that a supplier is willing to sell at each successively-higher Q-unit price
Systemic risk	System-wide risk, i.e., correlated risk arising for system operations as a whole
Transaction cost	Avoidable fixed cost incurred to organize a production process
Two-part pricing	Separately-requested compensation for avoidable fixed cost and variable cost
***u*-asset**	An asset with a standard unit of measurement u
Variable cost	Avoidable cost dependent on specific form of an undertaken action (e.g., production *level*)
Volumetric grid risk	Systemic risk arising for a grid due to possible net load imbalance

A.4 Cost Types for Grid-Supported RTO/ISO-Managed Wholesale Power Markets: Empirical Examples

Types of Avoidable Fixed Cost:

(1) **Capital Investment Cost.** Land acquisition, building construction; equipment purchases. Financed by *internal financing* (i.e., funds on hand), or by *external financing* taking two possible forms:

- ***Direct Financing:*** Sell *newly issued* securities in primary security markets to lenders willing to invest in risky assets (i.e., assets with chance of loss) that also offer a sufficiently high chance of gain;
- ***Indirect Financing:*** Obtain loans from financial intermediaries, typically secured by some form of collateral, that then result in amortized streams of payment obligations.

(2) **Transaction Cost.** Insurance, building code compliance, licensing fees, employee search. Transaction costs are typically financed by internal financing.

(3) **Opportunity Cost.** Expected net earnings from a best possible alternative use of assets, e.g., use of generation units directly (behind the meter) for local purposes.

(4) **Unit Commitment Cost.** Start-up, no-load, minimum-run, and/or shut-down cost that are incurred for ensuring the availability of power-paths for possible RTO/ISO dispatched delivery during a future operating period but are not dependent on the specific form (if any) of this delivered power-path.

Types of Variable Cost:

(1) **Fuel Cost.** Charges for pulverized coal, natural gas, nuclear, petroleum, and/or refuse-derived fuels as inputs to power production.

(2) **Labor Cost.** Salaries/wages for: legal/tax advice; advertisement; planning; supervision; trading-desk operations; maintenance; and repair.

(3) **Intermediate Good (Supply-Chain) Cost.** Rail/barge/pipeline/truck transport charges for fuel deliveries; replenishment of used-up supplies.

(4) **Equipment/Software Rental Cost.** Rental charges for office equipment, cars, and software licenses.

(5) **Depreciation of Owned Machinery.** Generation unit wear-and-tear due to start-up, normal, and/or shut-down ramping required to follow RTO/ISO-signaled dispatch set-points during successive operating periods.

(6) **Assessed Charges for Transmission Services.** Transmission grid operation and maintenance (O&M) costs allocated across market participants.

(7) **Variable-Cost Offsets from Sales of Valuable Bi-Products.** Revenue offset to variable cost of a product due to joint production, e.g., co-generation of valuable heating services along with power by Combined Heat and Power (CHP) units.

(8) **Disposal Cost for Waste Bi-Products.** Cost incurred by power plants (e.g., nuclear) to dispose of solid-waste output resulting from plant operations.

A.5 Swing-Contract Market Terms

Term	Description
***Acronyms and Generics*:**	
D	Generic symbol for a day
DPR	Dispatchable Power Resource
H	Generic symbol for an hour
IPR	Intermittent Power Resource
LAH(T)	Look-ahead horizon between close of $M(T)$ and start of T
LSE	Load-Serving Entity
$M(T)$	Swing-contract market for a future operating period T
m	Generic symbol for a DPR
n	Generic symbol for an IPR
p	Generic symbol for a power level (MW)
$\mathbf{p}$	Generic symbol for a power-path
$\mathbf{p}_b(T)$	Generic symbol for a power-path $(p_b(t) \mid t \in T)$
r	Generic symbol for a ramp-rate (MW/min)
SC	Swing contract taking the general form SC := $(\alpha, \mathbb{T}^{\text{ex}}, \mathbb{PP}, \phi)$
$\text{SC}_m(T)$	SC submitted by a DPR m to a swing-contract market $M(T)$ for operating period T
t^{ex}	Exercise time in an exercise set $\mathbb{T}^{\text{ex}}$
$t^{\text{ex}}_m(T)$	Exercise time in an exercise set $\mathbb{T}^{\text{ex}}_m(T)$
$T := [t^{\text{s}}, t^{\text{e}})$	Operating period with start-time t^{s} and end-time t^{e}
α	Offer price (\$) for a swing-contract SC
$\alpha_m(T)$	Offer price (\$) for a swing-contract $\text{SC}_m(T)$
ΔT	Duration of operating period T, measured in real hourly units (e.g., 0.6 h)
ϕ	Performance payment method for a swing contract SC that maps $\mathbb{PP}$ into payments
$\phi_m(T)$	Performance payment method for a swing contract $\text{SC}_m(T)$ that maps each power-path $\mathbf{p}_m(T) \in \mathbb{PP}_m(T)$ into a dollar payment (\$)
***Sets and Subsets*:**	
$\mathbb{B} := \{1, \ldots, NB\}$	Index set for the buses b of a transmission grid
$\mathbb{C}_j(b)$	Collection of customers serviced by load-serving entity $j \in \mathbb{LSE}(b)$
$\mathbb{L} \subseteq \mathbb{B} \times \mathbb{B}$	Index set for the distinct bus-to-bus line segments ℓ of a transmission grid
$\mathbb{L}_{O(b)} \subseteq \mathbb{L}$	Subset of transmission-grid line segments originating at bus b
$\mathbb{L}_{E(b)} \subseteq \mathbb{L}$	Subset of transmission-grid line segments ending at bus b
$\mathbb{LSE}$	Index set for the load-serving entities j participating in a swing-contract market
$\mathbb{LSE}(b) \subseteq \mathbb{LSE}$	Subset of load-serving entities j in $\mathbb{LSE}$ that service power customers at bus b
$\mathbb{M}$	Index set for DPRs m participating in a swing-contract market
$\mathbb{M}(b) \subseteq \mathbb{M}$	Subset of DPRs m in $\mathbb{M}$ that are electrically connected at bus b
$\mathbb{NG}$	Index set for IPRs n participating in a swing-contract market
$\mathbb{NG}(b) \subseteq \mathbb{NG}$	Subset of IPRs n in $\mathbb{NG}$ that are electrically connected at bus b
$\mathbb{PP}$	Set of dispatchable power-paths $\mathbf{p}$ offered by a swing contract SC
$\mathbb{PP}_m(T)$	Set of dispatchable power-paths $\mathbf{p}_m$(T) offered by a swing contract $\text{SC}_m(T)$
$\mathbb{P}_m$	Set of feasible sustainable power levels p (MW) for DPR m
$\mathbb{RR}_m$	Set of feasible ramp-rates r (MW/min) for DPR m
$\mathbb{T}^{\text{ex}}$	Set of possible exercise times t^{ex} for a swing-contract SC
$\mathbb{T}^{\text{ex}}_m(T)$	Set of possible exercise times $t^{\text{ex}}_m(T)$ for a swing contract $\text{SC}_m(T)$

A.6 Invertibility of Demand and Supply Functions

The following conditions suffice to ensure an *inverse* demand schedule $\pi := D_j(q)$ for a buyer j, defined as in **CM6**, can be inverted to obtain a well-defined *ordinary* demand schedule $q := D^o_j(\pi)$ for buyer j as defined in **CM3**, and vice versa, where $D_j(q)$ coincides with buyer j's marginal benefit function $MB_j(q)$ as defined in **CM5**. See Tesfatsion [43, Section 9.3.4] for extended discussion.

Suppose buyer j has a *benefit function* $B_j(q)$, defined as in **CM4**, that is non-decreasing, differentiable, and *concave* over $q \geq 0$. Evaluated at any Q-demand level $q' \geq 0$, buyer j's marginal benefit $MB_j(q')$ (measured in $\$/u$) as defined in **CM5** is then the non-negative derivative of buyer j's benefit function $B_j(q)$ with respect to q, evaluated at $q = q'$. The mapping $D_j(q')$ of q' into the non-negative *marginal* benefit evaluation π' ($\$/u$) $:= MB_j(q') := \partial B_j(q')/\partial q$ is buyer j's *inverse demand schedule for Q*. Finally, if buyer j's marginal benefit function $MB_j(q)$ is a *strictly* decreasing function of q for $q \geq 0$, a common "diminishing marginal returns" assumption for commodity spot markets, it can be inverted over $q \geq 0$ to give a *strictly* decreasing *ordinary* demand schedule $q := D^o_j(\pi)$ for buyer j. In this case, by construction, the Q-unit price π' that satisfies $q' = D^o_j(\pi')$ is the marginal benefit $MB_j(q')$ of buyer j evaluated at the Q-demand level q'.

The following conditions suffice to ensure an *inverse* supply schedule $\pi := S_i(q)$ for a supplier i, defined as in **CM10**, can be inverted to obtain a well-defined *ordinary* supply schedule $q := S^o_i(\pi)$ for supplier i as defined in **CM7**, and vice versa, where $S_i(q)$ coincides with supplier i's marginal cost function $MC_j(q)$ as defined in **CM9**. See Tesfatsion [43, Section 8.2] for extended discussion.

Suppose supplier i has a *total avoidable cost function* $C_i(q)$, defined as in **CM8**, that is non-decreasing, differentiable, and *convex* over $q \geq 0$. Evaluated at any Q-supply level $q' \geq 0$, supplier i's marginal cost $MC_i(q')$ (measured in $\$/u$) as defined in **CM9** is then the non-negative derivative of supplier i's total avoidable cost function $C_i(q)$ with respect to q, evaluated at $q = q'$. The mapping $S_i(q')$ of q' into the non-negative *marginal* cost evaluation π' ($\$/u$) $:= MC_i(q') := \partial C_i(q')/\partial q$ is supplier i's *inverse supply schedule for Q*. Finally, if supplier i's marginal cost function $MC_i(q)$ is a *strictly* increasing function of q for $q \geq 0$, a common "increasing marginal cost" assumption for commodity spot markets, it can be inverted over $q \geq 0$ to give a *strictly* increasing *ordinary* supply schedule $q := S_i^o(\pi)$ for supplier i. In this case, by construction, the Q-unit price π' that satisfies $q' = S_i^o(\pi')$ is the marginal cost $MC_i(q')$ of supplier i evaluated at the Q-supply level q'.

Author's Note

This study is a revised version of Working Paper #22005 (Iowa State University Digital Repository) submitted as a supporting document [45] for comments e-filed to FERC for Docket AD21-10-000 [16].

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