Locational Marginal Prices and Electricity Markets

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"…it is time to put the all-important question of the continued use of locational marginal pricing (LMP) in these market constructs on the table for serious scrutiny and discussion."[2]

I. Introduction

In the absence of a monopoly, electricity markets allow market participants to make choices about their real-time generation and power consumption, as well as injections and withdrawals from storage. The real-time price of power plays a major role in making these choices. Prices that are too high or too low distort real-time choices as well as associated expectations for long-run scheduling and investment decisions. Both economic theory and extensive practical experience demonstrate why the real-time locational marginal price (LMP) is the only real-time pricing system that supports an efficient wholesale electricity market. The Federal Energy Regulatory Commission (FERC) has wisely supported the development of LMP markets. The critical role for LMP was true in the past, is true today, and will be true and more important with the anticipated changing resources mix.

Locational marginal pricing has two important characteristics.[3] First, the prices are calculated from the system operator's actual operational security constrained economic dispatch solution for balancing load and generation. LMP prices support balanced supply and demand at each location and account for market participant bids and offers, the physical constraints of the transmission system and physical constraints on resource operation such as upper operating limits, and ramp rates. Second, LMP settlements are based on market clearing prices, as opposed to the pay-as-bid pricing designs used to determine constrained-on and -off payments in non-LMP pricing systems.[4]

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[2] Commissioner Mark Christie, Concurring Opinion, "Modernizing Wholesale Electricity Market Design," Federal Energy Regulatory Commission, Docket No.AD21-10-000, April 21,2022.

[3] The framework here is the generic economic dispatch model for congested power flows and abstracts from related issues associated with ancillary services and commitment decisions. See (Schweppe et al., 1988). For an introduction to locational marginal pricing see (Hogan, 1998). For the more general case, see (Gribik et al., 2007) and (Andrianesis et al., 2022).

[4] Constrained-up and -down payments compensate resources that would otherwise lose money if they followed their dispatch instructions. Constrained-off payments are conceptually the difference between the clearing price and the offer of the resource. Constrained-on payments are similarly conceptually the difference

A crucial element of LMP pricing is that it settles all resource injections and withdrawals at the same location at the same point in time at the same market clearing spot price. This is a fundamental feature of LMP pricing because LMP pricing is intended to provide prices that are consistent with least cost dispatch instruction and that reflect the cost of meeting load at each location at each point in time. The only alternatives to settling all injections and withdrawals of dispatchable resources at market clearing prices would be designs based on command and control or based on constrained-on and -off payments with pay-as-bid designs. As discussed further below, the market clearing price signal plays an important role in assuring that the injection and withdrawal decisions of distributed resources that are not dispatched by the system operator will support, rather than undermine, transmission grid reliability.

Recognize that the LMP price is only used to settle transactions in independent system operator (ISO) and regional transmission organization (RTO) spot markets. Market participants can enter into forward contracts, bilateral or exchange traded, that settle at prices other than the spot price. LMP spot prices that are the same for all resources and loads at a particular location are an essential underpinning of these forward contracts. Buyers and sellers could not contract forward efficiently if the seller would face a different spot price than a buyer at the same location.[5]

The inquiry from Commissioner Christie references a white paper that raises many issues for ISOs and RTOs given the changing nature of the electricity system over the clean energy transition.[6] These issues go beyond the LMP pricing model, and some are beyond the scope of the present paper. The main point here is that the offered criticisms of LMP are misplaced. While the authors of the white paper criticize ISOs for paying "all suppliers a single clearing price because they assume they can treat MWs of capacity and MWs of energy like commodities," this is precisely what LMP markets do not assume nor do.

In LMP markets, prices can vary by location at each interconnection point (node) on the transmission system and by time in five-minute increments. Power produced at locations where incremental supply cannot be dispatched to meet load due to transmission constraints will be paid a low price, while in non-LMP markets it is often paid the same price as generation that can be dispatched.[7] In LMP markets power produced when net demand is low will not be paid the same price as generation that is produced when net demand is high. In an LMP market, resources that cannot vary their output to produce more power when net load and prices are high or to produce less when net load and prices are low will receive lower average prices than resources that are dispatchable. Hence, in an LMP market fast ramping resources will earn larger margins than slow ramping units at the same location because they will produce more power when prices are high and less when prices are low. In an LMP market, power

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between the offer of the resource and the clearing price. Individual system operators may not report these payments consistent with these definitions and there can be offer caps and floors affecting the payments.

5 As discussed below, auctions of financial transmission rights allow suppliers and consumers (or their load serving entity) at different locations to enter into forward contracts, either bilateral or exchange traded contracts at trading hubs, without incurring congestion risk. No mechanism that we are familiar with has been developed that allows resources that are paid less than the spot price to enter into hedging contracts with loads.

6 (Clark & Duane, 2021).

7 See the discussion of constrained-off payments below.

consumers that can reduce their consumption when prices are high and increase consumption when prices are low will pay lower average prices than power consumers that continue to consume at high levels when prices are very high. Moreover, power intensive consumers that have choice in where they locate their operations can locate where prices are typically low due to transmission congestion. All of these outcomes in an LMP market raise social welfare by reducing consumption whose value is less than the cost of meeting that demand and increasing consumption that can be met a cost lower than its value.

Some of the asserted complaints about pricing are not related to price designs, but relate to the structure of subsidy designs for renewable resources, particularly wind and solar resources.[8] The underlying concern is that the subsidy designs in place were set up with the expectation of much lower energy prices than currently prevail, with the consequence that the subsidies are perceived by some to be too high at current energy price levels.

Whatever the merits of this concern, the critique of LMP is unsupported. First, these subsidy contracts and tax incentives were not put in place by ISOs or RTOs, they were put in place by state and federal governments and their regulatory agencies. While ISOs can and should attempt to inform the decisions of these state and federal entities regarding subsidy designs, it is not appropriate or even feasible for ISOs to undo these subsidy designs by reducing the spot prices paid for power produced by particular resources.

Second, any suggestion that ISOs and RTOs need to somehow reduce the payments to renewable resources in order to avoid excessive payments and consumer costs ignores the reality that LMP pricing is used to coordinate a day-ahead and/or real-time spot market in several large regions in which most (MISO) or virtually all (SPP and Western EIM) LSEs are regulated or public utilities. Moreover, within PJM and ISO New England there are individual states in which load is served by regulated or public utilities, and even in states with retail competition there are many public utilities that serve their load at cost-based rates.

There are no windfall profits on renewable generation owned by these regulated or public utilities, the higher revenues attributable to subsidies typically just reduce the cost of serving their load. It would make no sense to require these utilities to sell their renewable output at less than the market price at the same time that they must buy power to cover their load at the market price. Moreover, the revenues received by any renewable generation resources these utilities have contracted to buy power from will be determined by those contracts, not ISO pricing designs.

Furthermore, in states with retail competition, many retailers contract forward for power to lock in the cost of serving the retail loads they have, in turn, contracted to serve. Some of these forward contracts will be with renewable producers that may therefore not receive the benefits of high power prices, because they have already sold their power through the forward contract. For all of these reasons, it

8 Duane and Fisher (2022) p. 9 “causing consumers to pay more for wind and solar electricity than they should.”

does not make sense for ISOs and RTOs to distort market prices in order to reduce payments to renewable resources to offset what some commentators think are excessive subsidies to renewable producers.

If there is a concern with excessive revenues for future subsidized projects, that concern can be addressed by how the subsidies are structured. Furthermore, efforts by governments or regulators to price discriminate among suppliers, and pay each supplier just what is needed to elicit supply, inevitably result in shortages, market inefficiency and eventually inflated consumer costs. The US suffered the impacts of these types of designs in the natural gas industry and the crude oil and refining industry in the 1960s and 1970s. The abandonment of these policies and a shift to deregulated markets with market clearing pricing were important regulatory reforms of the 1980s that have served the country well over the following 30 plus years.[9]

Output related tax subsidies, procurement contracts that pay a positive price for output delivered at a location and time when the price is negative, and Investment Tax Credit designs that impose large penalties on batteries that charge with power withdrawn from the transmission grid, reduce market efficiency. But these choices are unrelated to LMP markets and outside the control of ISOs and RTOs. LMP markets make the best of these policy decisions from the perspective of reliably meeting load at least cost. In the context of environmental policy, it is noteworthy that LMP pricing has shown over the past 20 years that it is able to accommodate a wide variety of state and federal environmental policies. These include emission allowance costs for NO_X and SO_X and now for greenhouse gases, RECs,

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[9] There is a long history of attempts to apply non-uniform prices in the oil and gas industries. Wellhead regulation of natural gas was introduced in the 1950s and by the winter of 1977-78 had produced a supply shortage of regulated, interstate gas, a shortage that resulted in gas consumers "freezing in the dark." This situation led to the Natural Gas Policy Act (NGPA) which among other things eliminated the agency responsible for the wellhead regulation policy (the Federal Power Commission) and created FERC. The NGPA introduced a simplified, but still non-uniform, price regulation design. This design had broken down by 1983, leading to pipeline special marketing programs, the Maryland Peoples counsel case, Order 436, Order 636 and the end of price regulation of natural gas. See among many sources discussing this history, Breyer and MacAvoy (1974); MacAvoy & Pindyck (1975) and Bradley (1996.)

The market based uniform pricing of natural gas, has worked for well over 30 years now, through a gas glut, through high prices during late 2000 through early 2001, then low prices until 2003, then high prices through 2010, then low prices, through the outbreak and now with high prices in 2022, but high gas prices today are due to shortages in the world market while the US is a gas exporter.

There was a similar effort in the 1970s to discriminate in the pricing of "old oil," "new oil", high cost oil, and imported oil, with a related system of price controls on refined products. The regulation of refined product prices was intended to pass through the benefits of price capped domestic oil to consumers but actually served to subsidize the consumption of imported oil and refined products and to raise refined product prices. See among many sources discussing these polices and their impact Deacon (1978), Kalt (1981) Harvey & Roush (1981), Glasner (1985), Argwhal and Deacon (1985) Bradley (1996) and Rogers (2003).

production tax credits and investment tax credits. ISOs and RTOs did not develop these policies, but LMP markets accommodate them.

The mistaken focus on LMP pricing and markets in the context of environmental subsidy designs is highlighted by the discussion in a recent white paper[10] of proposals to replace the single clearing price in Great Britain. The Great Britain electricity market is not (yet) an LMP market. The current Great Britain market design clears day-ahead based on the fiction of a single pool wide price (it does not utilize LMP pricing) and utilizes a real-time balancing market that is not based on a least cost dispatch, restricts participation and settles on pay-as-bid, rather than market clearing prices. As a result of this design, not only do British power consumers pay high prices for power as a result of high gas prices, but they must also make high payments for power that is not produced (charges for constrained-off payments) under the current non-LMP design.

Returning to the focus of the benefits of LMP pricing with the evolving resource mix over the energy transition, we view the core benefits that need to be preserved as:

- Providing an efficient, transparent price signal for storage resources, behind the meter generation, price responsive loads and behind the meter networks, enabling these resources to support transmission grid reliability during stressed system conditions rather than undermining it;
- Enabling operationally feasible, financially binding, day-ahead market schedules that posture the system to meet expected system conditions, schedule the resources needed to balance net load during unexpected conditions, and incent resources to be available to cover their schedules in real-time;
- Providing efficient locational incentives that not only reduce consumer costs but also support transmission grid reliability by providing efficient incentives for the locational and supply of storage and ramping capability;
- Avoiding the consumer cost of constrained-off payments, associated with single and zonal price market designs;
- Supporting efficient and competitive entry to provide balancing by enabling forward hedging at locational prices that reflect transmission congestion and enable sale of exchange traded forward contracts supported by balancing capability;
- Having the ability to accommodate new concepts in dispatch design and the continued evolution of environmental rules and subsidies, including designs which reduce subsidies as market prices rise; and
- Ensuring the ability of LMP pricing designs to accommodate market power mitigation designs that are focused on sellers with the ability to profitably exercise locational market power without confounding market power with pay-as-bid incentives.

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10 Duane & Fisher 2022 p. 8

We begin in section II with a review of the factors that drove the implementation of LMP in US markets over the period 1996 through 2014. In section III we shift to a review of the benefits of LMP markets with the evolving resource mix from around 2014 to the distant future.

II. Overview of LMP Development

LMP pricing is typically associated with market-based pricing where prices are determined employing offer prices submitted by market participants based on their assessment of their incremental costs, rather than by offer prices based on administrative measures of incremental cost.[11] While LMP is used in many markets with retail competition (ERCOT, NYISO, PJM and ISO NE), LMP pricing can also be used for settlements among regulated and public utilities participating in a coordinated regional dispatch. In fact, LMP pricing is currently used in the US in regions in which most load is served by regulated or public vertically integrated utilities such as the Southwest Power Pool (often referred to as SPP), the Western Energy Imbalance Market (EIM) and MISO.

A fundamental driver for the implementation of LMP pricing was the development of decentralized markets coordinated by a system operator responsible for managing transmission congestion and avoiding transmission overloads. This role was traditionally filled by the control room of a vertically integrated utility that was able to use command-and-control to dispatch to balance generation and load while avoiding system overloads. Command-and-control dispatch was also used in tight power pools such as the New York Power Pool (predecessor to NYISO) and PJM in combination with what was known as "split-savings" pricing.[12] Command and control was workable within the power pools when the out-of-merit dispatch costs were small, the participants were in principle prohibited from exploiting the inefficient pricing, and the participating regulated utilities were able to recover their costs in their regulated retail rates.

The workability of command-and-control dispatch within the tight power pools came under pressure in the 1990s. Increases in gas prices created larger transmission congestion costs, along with the potential, or sometimes certain, inability of some utilities to recover any additional costs in retail rates, rates which were already under pressure from high costs (associated with out of market qualifying facility costs such

[11] However, LMP pricing can be utilized in combination with cost-based offers as it was in PJM from April 1, 1998 to April 1, 1999. Beginning April 1, 1999, market-based offers were used for the dispatch in unconstrained regions and to manage congestion on the three main voltage constraints within PJM. Cost-based bids continued to be submitted and used to manage congestion on local transmission constraints that had not been deemed competitive. The PJM market power mitigation design has evolved tremendously over time and is not discussed in detail here as that would be a substantial paper in itself. See PJM Market Monitoring Unit, 2004 State of the market report, March 8, 2005 pp. 19, 63-67 for a review of the early design.

[12] At a conceptual level, split savings designs calculate the savings from the actual dispatch compared to each company's hypothetical individual "own load" dispatch and then distributes the savings according to a formula that splits the savings. The time granularity used for this calculation can vary from system to system and there is often enormous complexity involved in accounting for a variety of factors including bilateral transactions. These designs historically created arbitrage opportunities and incented trading outside the pool. See Thomson, (1995).

as those due to the New York 6 cent law, or other factors).[13] The legacy split-savings pool pricing mechanisms would clearly be unworkable in a decentralized market with unregulated participants, providing a further driver for the development of LMP pricing designs by the member systems of the New York Power Pool and the PJM supporting companies.

While most U.S. ISOs and RTOs employ LMP to settle both the real-time dispatch and their day-ahead market, LMP pricing can be implemented solely in real-time for settlements without the implementation of an ISO coordinated day-ahead market.[14] Although LMP can and has been implemented solely for real-time settlements, a major benefit of LMP pricing is that it enables the implementation of an operationally feasible day-ahead market, as discussed in greater detail below.

Organized markets with LMP designs are essential in supporting forward hedging arrangements and enabling exchange traded financial contracts that can settle against the spot price, with congestion hedged through financial transmission rights (FTRs). Point-to-point transmission rights are essential to support long-term contracting between load and generation. From the earliest days of electricity market reform, continuing until now, there is no feasible system of transmission rights other than FTRs that operate in connection with LMP market design. Nothing other than the LMP/FTR combination works in theory to support efficient participation in economic dispatch in a decentralized market, while efficiently managing congestion and supporting forward contracting between resources and power consumers at different locations. We also know from 20 years of experience that nothing else works in practice in a market setting.

III. LMP Benefits with 1995-2014 market conditions and resource mix

LMP pricing was developed and initially implemented in the 1990s, and has provided important benefits when used under those conditions and resource mix. The primary benefit was that LMP pricing was consistent with, and supported economic dispatch, and did this without the need for constrained-on and -off payments. Eliminating the need for constrained-off payments eliminated an important driver for the imposition of entry barriers in non-LMP markets. An important benefit that has been realized over time is that LMP supports the implementation of operationally feasible day-ahead market. In addition, LMP pricing has been able to accommodate the implementation of sophisticated market power mitigation designs. Moreover, commodity trading exchanges have evolved with the development of

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[13] The authors began working on the development of LMP pricing systems with the member systems of the New York Power Pool and some PJM utilities prior to the issuance of order 888.

[14] This was the case in PJM from April 1, 1998 to June 1, 2000 and was also the case in the Southwest Power Pool from 2007 to 2014. LMP pricing has also been used for real-time settlements in the Western EIM since 2014, with discussions of the prospective implementation of a day-ahead market across some or all of the Western EIM footprint continuing. The day-ahead market for the Western EIM is referred to as EDAM, extended day-ahead market. Documents relating to its design can be found at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market

LMP markets by developing a wide variety of exchange traded hedging products for LMP based electricity markets.[15]

1. LMP is consistent with, and supports, centralized economic dispatch

Open Access and nondiscrimination, combined with efficient operation of the transmission system, requires LMP. LMP is the only pricing system that supports the efficient dispatch because LMP prices are calculated based on the marginal conditions in the dispatch. Any pricing system that sets prices that are inconsistent with the real-time dispatch necessarily requires discriminatory pricing, limits on access, constrained-on and –off payments, or reliance on command and control to maintain reliability

Many early, and sometimes continuing, electricity market design debates include a claim that there is or should be a single market-clearing price for the entire market, or at least that the effect of transmission congestion could be limited to a few large pricing zones that would be able to represent the major effect of transmission congestion. This was and is an appealing argument as it seems much simpler to have a single liquid market that covers a large proportion of total power production.

However, the claimed simplicity turned out to be a mirage. It is often asserted that locational pricing is not needed because there will not be material congestion, but this assertion has turned out to be untrue again and again in actual system operation. Transmission constraints are ubiquitous, with impacts that can sometimes be counterintuitive.[16] The true locational marginal cost of meeting load can be both higher and lower than the marginal costs of any of the operating generators due to interactions that require redispatch of multiple generators (some up, some down) to meet a marginal increment of load at a particular location.

Furthermore, in circumstances in which there is no transmission congestion, LMP would result in essentially a single market-clearing price. Under these conditions, LMP would capture the purported benefits of a single price or zonal system. Hence, single or zonal pricing models differ from the LMP model only under conditions of congestion where the single and zonal pricing models require reliance on command and control or constrained-on and –off payments to work.

At the opposite extreme are the market models that attempt to differentiate power flows as multiple products with separate pricing and allocation rules for each. However, a core fact of the well-recognized requirement for instantaneous power flow balancing is that, at a particular moment and location, power flows are indistinguishable. In other words, power at a point in time and place is a commodity. It does not matter how it was produced, in fact it is meaningless to ask which resource produced the power consumed at a particular location at a particular moment in time. The LMP model defines the market-clearing prices for this building-block commodity.

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[15] See ICE https://www.theice.com/products/Futures-Options/Energy/Electricity and Nodal Exchange, contract specifications at https://www.nodalexchange.com/regulation/nodal-exchange-regulation/participant-agreement-and-rulebook/

[16] These conditions are well understood by system operators, and have been explained and illustrated for interested market participants willing to ask.

While it is sometimes asserted that locational pricing creates local market power, this is not the case. Locational market power is not reduced by declaring that prices will be the same across artificially large zones. Locational market power still exists, it would just be exercised in a different manner. The expected liquidity of a large zone is a mirage because the commodities being traded at different locations are not really the same. Power at different locations or produced and consumed at different points in time is not homogenous. Incremental load within transmission constrained regions cannot be met with generation located outside the constrained region. In the end, someone picks up the cost of a market that assumes power is fungible locationally when it is not, often through socializing the cost across loads. This fiction often results in single price markets that lack effective mechanisms to identify and mitigate the exercise of locational market power in the balancing market.

While managing transmission congestion by defining generator pricing zones may seem to be a workable middle ground, it typically creates even more problems than a single market price design.[17] Moreover, when conditions mandate a change in a zonal definition, history shows that there is no workable way to adjust zonal definitions on an ongoing basis. The only stable design is one that goes all the way to LMP with a possible unique real-time price for every location. In theory and in practice, LMP is the truly simple system.

2. LMP avoids need for constrained-on and-off payments to manage congestion

Vertically integrated utilities do not need to use LMP pricing to support their economic dispatch to meet load, as the system operator of the vertically integrated utility is sending dispatch instructions to employees who have no economic incentive to depart from those instructions. However, command-and-control does not work in a market-based system, as requiring generators to operate at prices that do not cover their costs is not sustainable. Non-locational pricing systems inherently create situations in which the price is too high or too low to make the efficient dispatch profitable for some generators. The zonal price will exceed the incremental cost of generators in the constrained-down region who would find it profitable to operate when they need to be dispatched down. At the same time, the zonal price can be too low relative to the incremental cost of generators in the constrained-up region who would find it unprofitable to operate when they are dispatched up.[18]

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17 In particular, if the zones are used to dispatch generation, the zonal design can result in unmanageable congestion, unused transmission capacity, and uneconomic dispatch because of the fictions underlying the zonal definition. There is an extensive, detailed discussion of these issues in the 2009 ERCOT market report. See Potomac Economics Ltd, "2009 State of the Market Report for the ERCOT Wholesale Electricity Market, "pp. 76-90. A similar discussion of these issues with data for prior years can be found in earlier state of the market reports. ERCOT implemented a nodal LMP design at the end of 2010.

18 Supply exceeds demand (including exports) at the clearing price inside a constrained-down region in a single price market. Some low-cost generators in constrained-down regions are therefore directed to reduce their output below the amount offered at the clearing price in order to avoid transmission overloads. Conversely, supply (including imports) exceeds demand within constrained-up regions in a single price market. Some high-cost generators are therefore directed to increase their output above the amount offered at the clearing price in order to balance load and generation.

These inconsistencies between prices and dispatch instructions in single or zonal pricing designs create a need for a mechanism to incent or require generators to follow dispatch instructions. Single or zonal price market systems typically rely upon constrained-on and-off payments to incent dispatchable resources to operate consistent with system operator instructions. The constrained-on payments that go to generators whose incremental costs exceed the single price do not necessarily inflate consumer costs relative to an LMP market, as consumers would pay higher prices for this constrained-on output in an LMP market as well. However, in practice these single or zonal pricing designs may inflate the cost of congestion management if the real-time dispatch is not a full least cost dispatch in which all resources can participate, but is instead a balancing market with limited participation, pay-as-bid pricing, and a dispatch that differs from a contingency constrained least cost dispatch.[19]

A fundamental problem with non-LMP markets from the standpoint of consumer costs is the further need to make constrained-off payments to generators that must be dispatched below the level that would be profitable based on the single or zonal price in order to avoid transmission system overloads. These constrained-off payments do not contribute to meeting load and inherently serve to increase consumer costs, even with cost-based bidding by suppliers. The constrained-off payment is generally calculated as the difference between the non-LMP price and the resource incremental offer price. The constrained-off payment therefore increases as the offer price falls. The potential for inflated consumer costs is increased under market-based pricing in which resources that expect to be constrained-off, and have some degree of market power in reducing output within a generation pocket, can submit artificially low offer prices and thereby inflate the constrained-off payments they receive.[20] This was referred to as

[19] See, for example, the discussion of "nodal price chasing" in Ontario Energy Board, Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity Markets, for the period from May 2017-October 2017, December 2019, pp. 21-25; and Ontario Energy Board, Market Surveillance Panel Report 36, March 2022, pp. 25-26.

[20] It is noteworthy that these suppliers would not possess market power in the usual sense of being able to raise prices by withholding output. They could lack even the slightest ability to profitably raise prices by raising their offer prices, yet be able to raise constrained-off payments by lowering their offer prices without facing any competition in relieving congestion if they are a major source of the flows that create the congestion. This situation can also arise in LMP markets when there are deratings of the transmission system between the day-ahead market and the real-time dispatch but it happens every day in non-LMP markets with constrained-off payments.

the INC/DEC game in the original CAISO market (1998-2009).[21] Essentially the same problem appeared in the Texas ERCOT market and was among the factors leading to the subsequent LMP reform.[22]

The Ontario Independent Electricity System Operator (IESO) has also had issues with inflated constrained-off payments under its current non-LMP design. These excess costs have been discussed extensively by the Market Surveillance Panel.[23] A noteworthy source of excess costs has been constrained-off payments to import schedules.[24] The Ontario IESO has also limited constrained-off payments by implementing an offer price floor for wind in September 2013, requiring that 90% of wind resource output be dispatched off at \$-3/MWh and the rest at -\$15/MWh.[25] We regularly see situations in LMP based markets in the US in which intermittent resources are dispatched off economically at low or negative prices at some locations on the grid while prices are high at other locations. Under a non-LMP pricing design, these situations would either lead to extremely large constrained-off payments or lead to the implementation of price floors and command and control management of intermittent resource output.

While the excess costs associated with constrained-off payments are undesirable for a number of reasons, these payments are necessary in market-based non-locational pricing systems to avoid transmission system overloads. The experience with PJM's 1997 market implementation is instructive. The single-zone market was developed by Enron and Philadelphia Electric Company (PECO). FERC required PJM to implement this design in preference to the LMP system offered by the remaining supporting utilities. The design called for a single pool price across the whole system and allowed for

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21 See for example, Opinion of the ISO Department of Market Analysis, December 20, 1999 regarding "the DEC Game," the discussion of the "DEC Game" in California ISO;" CAISO filing letter for Amendment 42, ER02-922-000, January 31, 2002 pp. 8-12; 2002 Annual Report on Market Issues and Performance," April 2003, pp. 8-7 to 8-8 the discussion of Palo Verde Negative Decremental bidding in California ISO, California ISO, Amendment to Comprehensive Market Design Proposal, Docket No. ER-02-1656 and EL01-68, July 22, 2003 p.29-30; "2003 Annual Report on Market Issues and Performance," p. 7-2. California ISO "2004 Annual Report on Market Issues and Performance, April 2005, pp. 6-14 to 6-15; California ISO, Department of Market Monitoring, 2005 Annual Report, Market Issues and Performance, April 2006 pp.6-1 to 6-5; California ISO, Department of Market Monitoring, 2006 Annual Report, Market Issues and Performance, April 2007 pp.6-1 to 6-5..

22 See, for example, Potomac Economics Ltd, 2009 State of the Market Report for the ERCOT Electricity Markets, July 2010 pp. 99-102.

23 See for example, Ontario Energy Board, Market Surveillance Panel, Monitoring Report 32, July 16, 2020 pp. 19-21; Ontario Energy Board, Market Surveillance Panel, "Congestion Payments in Ontario's Wholesale Electricity market: An Argument for Market Reform," December 2016.Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011, pp.70- 73, 108-110 Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, November 2010 to April 2011, November 2011 pp. 134-137.

24 Ontario Energy Board, Market Surveillance Panel, "Congestion Payments in Ontario's Wholesale Electricity market: An Argument for Market Reform," December 2016. In particular see the discussion of constrained-on and-off payments to imports pp. 35-36; 44-45; and 49-50. Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011, pp. 72-73.

25 See SE-91 [http://www.ieso.ca/Documents/consult/se91/se91-20101104-Renewable_Integration-Stakeholder_Plan.pdf (esmap.org)](http://www.ieso.ca/Documents/consult/se91/se91-20101104-Renewable_Integration-Stakeholder_Plan.pdf) and Stakeholder Engagement Prereading, "Negative pricing," February 13, 2020.

constrained-on payments, but did not provide for constrained-off payments.[26] Hence, if transmission congestion developed, generators that were dispatched down to manage congestion had to forgo production that would have been paid the pool price, despite having much lower offer prices and costs. At the same time, resources that were dispatched, or self-scheduled, or non-firm imports that were willing to buy through congestion under the terms of the tariff, were paid a price for their output that was much higher than their offers.

When transmission congestion developed on a predictable basis in June 1997 following implementation of this single price market, these economics induced a downward death spiral in self-scheduling by an increasing number of resources in western PJM.[27] This design had the consequence that utilities that did not self-schedule, or could not self-schedule their resources because of the terms of joint unit agreements, were required to purchase power at prices far above the cost of the resources that were dispatched off in favor of self-scheduled generation and non-firm imports willing to "buy through" congestion.[28]

The prospect of being unable to manage congestion and avoid overloads on the eastern interface caused PJM to make a unilateral filing at FERC at 4:59 p.m. on Friday June 27, 1997 with an effective date of 5 p.m. on June 28, 1997, that eliminated the ability of non-firm import transactions to effectively self-schedule, allowing PJM to curtail these transactions on a non-economic basis when they contributed to congestion on the transmission system.[29] These changes temporarily enabled PJM to manage congestion within the Enron-PECO pricing design for a while, but by August 22, 1997 PJM market participants had identified market rules that allowed them to circumvent the June 27 curtailment rules. The resulting loss of PJM's ability to manage congestion within its economic dispatch culminated in PJM using the declaration of a minimum generation emergency on August 22 to allow it to curtail transactions on a non-market basis.[30] PJM subsequently changed its operating procedures to not

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26 See FERC February 28, 1997 order in Dockets Nos. OA97-262-000 and ER97-1083-000, pp. 4-5 "We hereby inform PJM that it should implement, subject to refund and further order as noted above, the PECO Energy congestion pricing proposal."

27 See, for example, PJM filing Docket No. ER97-3463-000 June 27, 1997, at p. 5. "Two out of four companies on the west side of the east/west operating constraint have begun such self-scheduling since the beginning of June and a third western company has indicated its intent to do so." See also William Hogan, Strengths and Weaknesses of the PJM Market Model, p. 9.

28 See PJM filing Docket No. ER97-3463-000, June 27, 1997 at p.6.

29 See PJM filing Docket No. ER97-3463-000 June 27, 1997. The filing noted regarding the self-scheduling that "It also results in reliability concerns because more generating units are being self-scheduled, thus excluding themselves from redispatch. PJM thus has fewer units under its immediate control, and this reduces PJM flexibility in responding to operating conditions that occur on the PJM system.

…. Although this situation has not yet threatened PJM's reliability, it created the potential for serious problems. For example, recent instances have occurred where generators on the reduce side of PJM's constraint have not been following PJM's orders during redispatch operations due to the economic disincentives to reduce their generation." Filing letter P. 5. These changes were approved by FERC on July 18, 1997 with an effective date of June 28, 1997, see 80 FERC ¶61,069.

30 PJM posted the following explanation of the events on August 22, 1997 with the minutes of its August 27, 1997 Market Operations Committee Meeting.

accept new non-firm or secondary service transmission schedules that would require re-dispatching generation, effective October 1, 1998, thereby undoing Open Access.

Based on this experience, in late 1997 FERC approved a shift to an LMP market design,[31] and PJM implemented a cost-based economic dispatch with locational marginal prices that applied to load and generation at each location on April 1, 1998. In 1999, FERC approved a revised "Market Based" pricing approach where generator engineering cost estimates would be replaced by market bids and offers for most market participants. Similarly, FERC approved an LMP design for NYISO in 1999[32] and the process of implementing LMP markets continued to include all the organized markets.

While PJM did not have constrained-off payments for imports into the constrained-down west region in 1997, imports into constrained-down regions have proved to be a challenge for other ISOs with non-LMP markets. For example, the IESO has encountered challenges with imports from Minnesota (MISO) and Manitoba into the constrained-down northwest region.[33] Similarly, Great Britain has encountered issues with imports from Norway when Northern England is constrained-down. System operators with non-LMP pricing systems face poor choices in managing imports into constrained-down regions in which the single market settlement price may greatly exceed the incremental dispatch offer. If they make constrained-off payments based on import offers, import suppliers can submit lower priced offers that utilize the full import capability of the transmission system, knowing that they will be constrained-down and receive constrained-off payments for not producing power. Conversely, if import suppliers cannot be dispatched down in exchange for constrained-off payments, imports may displace lower cost zero emission output. These situations do not arise in an LMP market as the price in the constrained-down region is consistent with the dispatch, and low priced import supply offers into a constrained-down region are paid an appropriately low market clearing price.

"Approximately 11:00 PJM had dispatched all units in Central and Western PJM down to their economic minimum cost. No further units remained in the central or west to control the transfer limit. Additional generation in the East was still required. No generation in the central or west had been scheduled by PJM. All generation operating in these areas was self-scheduled by the owning company.
At 11:21 PJM issues a minimum generation declaration for western and central PJM.
At 11:21 -11:30 PJM polled all companies affected by the minimum generation declaration to determine if any generation changes were anticipated. No generation changes were reported.
At 11:30 PJM started curtailing spot market transactions from the west that were bid in a price of zero. Approximately 1200 MW of energy was bid in at zero. Curtailments were made based on the timestamp of when the bids were received. The initial curtailment was for 574 MW to start at 11:45"
PJM System Operations Overview August 22, 1997.

[31] November 25, 1997 FERC order in dockets Nos. ER97-3189 and EC97-38.

[32] See January 27, 1999 FERC Order dockets Nos. ER97-1523, OA97-470, and ER97-4234, 86 FERC ¶61,062

[33] Ontario Energy Board, Market Surveillance Panel, "Congestion Payments in Ontario's Wholesale Electricity market: An Argument for Market Reform," December 2016 pp. 49-50; Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011, pp.72- 73.

3. LMP allows implementation of financially binding, operationally feasible, day-ahead markets.

Operationally feasible, financially binding, day-ahead market schedules were desirable in the 1990s because they ensured that slow starting units that would be needed to meet load would be committed. Operationally feasible and financially binding day-ahead markets had been implemented in NYISO, PJM, ISO New England and MISO by 2005. The CAISO and Ontario IESO tried to develop designs for operationally feasible, financially binding day-ahead markets for their 1998 and 2002 market designs. Their goal was to create market designs which would support financially binding schedules for resources that would need to be dispatched up out of merit in real-time and receive constrained-on payments. However, the CAISO and IESO were unable to develop a workable design based on their single and zonal price market designs that would not have resulted in excess consumer costs absent LMP pricing in real-time.[34]

The CAISO explained the importance of an operationally feasible day-ahead market in its July 22, 2003 MDO2 filing, observing that:

> Because the CAISO's congestion management system does not model intra-zonal transmission constraints and accepts schedules from SCs that are not physically feasible, the CAISO has no effective process for managing intra-zonal congestion in the forward market. As a result, instead of managing intra-zonal congestion the same way the CAISO manages inter-zonal congestion, i.e. by ensuring that schedules cannot cause congestion, the CAISO has been forced to accept forward schedules that create congestion and attempt to manage such intra-zonal congestion in real-time. This is a difficult and burdensome process that demands a disproportionate share of grid operators' time, forces them to scramble in Real-Time to keep the grid running reliably, and impinges on their other responsibilities.[35]

One core problem in developing operationally feasible day-ahead markets on congested transmission systems based on a single or zonal price (such as those of CAISO and the IESO) is that without LMP prices in real-time that would be used to settle deviations between day-ahead market schedules and real-time supply, resources scheduled out of merit in an operationally feasible day-ahead market could fail to perform and settle their imbalance at a system or zonal price that would be lower than their payment in the day-ahead market. A second core problem in single or zonal pricing designs was that not only would a non-LMP day-ahead market do nothing to reduce the magnitude of constrained-off payments, it would likely increase them by providing more opportunity for resources to enter into phantom day-ahead market positions that would be constrained-off in real-time. These phantom schedules would not only

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[34] See Ontario IESO, "Day-ahead Market Evolution Preliminary Assessment," May 5, 2008; Michael Cadwalader, Scott Harvey and Susan Pope, "Comments on the Evaluation of an Unconstrained Price Day-Ahead Market Compared to an Enhanced Day-Ahead Commitment Process," prepared for the IESO, September 3, 2008.

[35] California ISO, Amendment to Comprehensive Market Design Proposal, Docket No. ER-02-1656 and EL01-68, July 22, 2003, p.28. Footnote 30 outlines the operating challenges described by James McIntosh, director of grid operations. "SCs" are scheduling coordinators in California ISO terminology, the entities responsible for interactions with the CAISO for load, supply, or both.

increase the constrained-off payments borne by power consumers, they would further depress the unconstrained day-ahead price relative to the actual cost of meeting load in constrained-up regions in real-time. These phantom schedules would provide little or no benefit for forward scheduling of needed generation or imports that would be out-of-merit at the single day-ahead market price, while potentially increasing the scheduling of uneconomic exports in the day-ahead market that would be constrained-off in real-time.

In another example of the operational challenges created by non-LMP pricing designs, European day-ahead markets are not operationally feasible and require the system operator to not only balance the system for unexpected events in real-time but also to re-balance the system to compensate for infeasible day-ahead schedules on a pretty much continuous basis. The pressure for reform of these markets continues in addition to dealing with the challenges created by the war in Ukraine.

The lack of an operationally feasible day-ahead market can create operating challenges under normal market conditions, but these challenges can turn into serious reliability issues under stressed system conditions such as those prevailing in the CAISO during May and June 2000. The reliability risks also rise as the magnitude of the differences between the day-ahead market schedules and the resources actually needed to balance load and generation increase. Balancing the electric system in real-time when there are substantial unexpected events that cause real-time conditions to change is always challenging, but LMP enables operationally feasible, and financially binding, day-ahead markets that help minimize these problems.

4. LMP avoids the need for the ISO to impose rules that limit entry of new resources in order to attempt to limit the magnitude of constrained-off payments

The potential for high constrained-off payments to generation located in constrained-down regions provides a rationale for ISOs to impose restrictions on entry in constrained regions in order to reduce magnitude of the required payments for not producing power. However, these restrictions on entry not only deter inefficient entry incented by constrained-off payments, they can also create barriers to the entry of new efficient, low emitting generation that would replace high cost, high emission generation. For example, this was the case in ISO New England's system impact study procedures that Bucksport and Champion (potential entrants into the New England electricity market) noted in their complaint. Bucksport and Champion observed that these system impact studies "assume that all existing and new generation must be fully integrated with load, such that any generator located anywhere in NEPOOL must be able to serve load anywhere in NEPOOL," "assume the most extreme operating conditions that are inconsistent with industry standards and, therefore, assume that any constraint on the system can only be remedied through the construction of transmission upgrades," "assumes that all projects in the queue ahead of that project studied will be built, the SIS necessarily produces inaccurate results" and finally "grandfather preferential rights of existing generators and 'goldplates' the NEPOOL transmission system."[36] The relevant elements of the Champion Bucksport complaint were granted and NEPOOL's proposed changes to its interconnection study rules were rejected by FERC in 1998.[37]

In addition, generation that may be constrained-down in low load conditions may be needed to meet load in high load conditions. It is noteworthy that the debate over the amendment 19 "NewGen" restrictions in California took place in 1999, just before the well-known California electricity market crisis. The final FERC order rejecting the proposed "ACCM" rules that would have limited entry by either requiring transmission upgrades or the application of discriminatory settlement and dispatch rules to any new generator that created congestion in any interconnection study scenario was issued at the end of January 2000,[38] shortly before it became apparent to everyone in the west that the real problem in CAISO was not too much generation receiving constrained-off payments, but too little generation to meet load over the summer of 2000.

An indirect way of limiting entry in order to contain the level of constrained-off payments would be to introduce transmission access charges for generators, with charges that are high in the constrained-down region and low or even negative in constrained-up regions. Great Britain introduced this type of access charge in the 1990s which has evolved into the current "TNUOS" charges. A detailed discussion of the British TNUOS design is well outside the scope of this overview, but we note that the original transmission access charges, and now TNUOS charges, have failed to manage the huge rise in constrained-off payments over the past decade.[39]

Moreover, the entire concept of using transmission access charges to manage interconnection was developed more than 20 years ago in the context of investments in thermal generation. It will become increasing unworkable with the evolving decentralized resource mix. In today's world transmission access charges are useless in managing the congestion created by intermittent resources whose full output is needed to meet load at some times of day or under some conditions, but whose full output cannot be delivered to load or stored at times of very high intermittent resource output. Today it is not enough to deter inefficient investment in constrained-down locations, the electricity market design must be able to efficiently manage the unavoidable transmission congestion associated with varying levels of intermittent resource output over the day or year.

Similarly, transmission access charges will not discourage inefficient investments in behind the meter generation by power consumers in constrained-down regions who pay an inflated uniform price.

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36 See Complaint of Champion International Corporation and Bucksport Energy LLC, EL98-69-000, August 7, 1998 p. 5. The complaint also raised issues regarding NEPOOL governance and study queues.

37 See ISO New England filing in Docket ER98-3853, July 22, 1998 at 14-15 and 18-19; FERC order in Docket ER98-3853-000 85FERC ¶61,141. See also the Bucksport order in EL98-69-000, 85FERC ¶61,142 October 29, 1998, and the Champion/Bucksport Complaint in Docket EL8-69-000, August 7, 1998.

38 See CAISO June 23, 1999 filing letter, Docket No, ER99-3339-000, January 31, 2000, FERC order, 90 FERC ¶61,086. January 31, 2000 and Scott Harvey and William Hogan, "Comments on the California ISO's New Gen Policy," July 27, 1999.

39 See FTI, "Operation market design: Dispatch and Location, preread for National Grid ESO workshop on January 17, 2022," slide 14 historical constraint costs.

Transmission access charges are not suited to providing a signal that discourages investment in additional intermittent resources, most of whose output would be constrained-off, while at the same time encouraging retention of, or investment in, dispatchable resources at the same location that could operate when wind and solar output is low. Designs based on using transmission access charges to reduce uneconomic entry and limit constrained-off payments also do not readily send an efficient signal for investment in, and operation of, energy storage resources in constrained-down regions. While these energy storage resources could offer injection schedules that might need to be constrained-off, under an LMP market design the storage resources could store energy if the LMP price at their location was low, and thereby reduce the need to constrain off other resources.

5. Market power mitigation

Because LMP pricing sets market-clearing prices, sellers do not have to bid the market clearing price in order to be paid the market clearing price, that is, the same price received by other sellers at the same location. The ability of sellers to offer supply at their incremental cost and be paid the market clearing price at their location facilitates the identification of the potential exercise of market power and enables the application of market power mitigation designs, without artificially suppressing prices.[40] This is impossible in non-locational price designs with pay-as-bid balancing mechanism where sellers have to bid the market clearing price in order to be paid the market clearing price; that is, in order to be paid the same price as other suppliers dispatched in the balancing market to meet load at the same location. Even low-cost suppliers have an incentive to offer supply at the expected market clearing price in pay-as-bid market designs, making it very difficult to identify anomalous offers or to apply market power mitigation designs. In addition, if even small producers that do not possess market power have an incentive to submit offers based on the expected market price, the scope of mitigation will expand beyond large suppliers to become pay as ISO estimated cost bidding and compensation.

Moreover, with the implementation of reserve shortage pricing within LMP pricing designs, as in NYISO, MISO, PJM, ERCOT, ISO New England and SPP, prices can reach high levels during emergency conditions without the need for any seller to submit high offer prices. While the CAISO does not have a reserve shortage pricing design in its day-ahead market or in real-time, following the August 2020 blackout rules have been implemented to ensure that prices are set at appropriate levels when the CAISO finds it necessary to take the step of "arming" load for shedding in order to meet its mandatory WECC reserve requirements, with the armed load replacing non-spinning reserves that are dispatched to balance load and generation [41]

[40] We will not go into the details of market mitigation designs in LMP markets. However, these designs apply mitigation based on "reference prices" or "default energy bids" when triggered by congestion. Even when mitigation is applied, all resources are paid the market clearing price, which could be set by a mitigated offer, the offer of a resource not subject to mitigation, or a reserve shortage or transmission penalty price.

[41] See CAISO filing letter in Docket ER21-1536, March 26, 2021, pp. 32-36; California ISO, Market Enhancements for Summer 2021 Readiness, Draft Final Proposal, February 18, 2021 pp. 33-36.

6. Market liquidity

As LMP based markets have been implemented and developed over the past 20 years, forward markets have evolved in parallel, with LMP enabling the develop of exchange traded financial hedges.[42] LMP provides much greater liquidity in forward markets for generation located within constrained areas. Market participants can monetize their locational value in forward markets by selling power at trading hubs and buying counterflow FTRs from their location to the trading hub, realizing the value of the congestion management they provide in the forward market, or they can sell their output at a hub in a constrained-up region.

There is, on the other hand, no market mechanism for resources in constrained-up regions to sell forward in balancing markets in non-LMP systems because they can only sell their output at its actual value in the pay-as-bid balancing market, and only near real-time. Non-LMP prices provide inappropriately high liquidity for resources that cannot be dispatched to meet load,[43] while providing poor liquidity for resources in constrained-up regions that can be dispatched to meet load, but can only sell their power at its actual value in the real-time balancing market. There is no forward market for constrained-on payments in non-LMP market designs. Hence there is no market mechanism for generation located in constrained-up regions to lock in the value of their generation in forward contracts. Instead, they must realize the value of their asset day by day in a pay-as-bid market for constrained-on generation.

Hence, non-LMP markets are backwards in terms of liquidity, providing liquidity in forward markets for assets that cannot be dispatched to meet load, while providing no liquidity for generation located where it is needed to balance net load in real-time but unable to realize the balancing market value of their asset in forward contracts. This design greatly favors incumbent generation in the constrained-on region which does not have to compete in forward markets with new entrants, as the entrants cannot enter into forward contracts at balancing market prices, and the incumbents would be able to reduce their balancing market offers if entry were to occur. In LMP markets, on the other hand, entrants have the ability to sell power forward at prices that reflect expected balancing market prices, either through bilateral contracts or exchange traded contracts, locking in returns before they enter the market.

IV. LMP and the Evolving Resource Mix 2016-2050

In this section we turn to the role of LMP with the evolving resource mix in the US over the past 7-8 years and the prospective benefits of using LMP pricing to support the energy transition in the US and around the world over the next 10, 20 and 30 years. The transmission congestion that was a recurrent

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42 The huge number of financial hedges of various sorts traded in power market hubs on ICE and Nodal Exchange is an excellent illustration of this development.

43 Constrained-off payments enable resources whose output cannot be dispatched to sell power forward at the same price as generation that can be dispatched to meet load.

pattern on the US and Ontario transmission systems over the period 1997 to 2014 is likely to be even more chronic as the resource mix evolves towards greater reliance on intermittent resources. There will inevitably be transmission congestion when intermittent resource output is unusually high. It will never be economic to expand the transmission grid to accommodate output levels that only occur sporadically, or only for a short time each day. The need for a pricing system that efficiently manages congestion will likely become more, not less, important in coming years.

As highlighted in the introduction, the core benefits of LMP with the evolving resource mix over the next 30 years will be an extension of its benefits over the past 20 years.

1. LMP market clearing price provides an efficient price signal consistent with market conditions for storage resources and for price responsive off dispatch resources

With the evolution of the resource mix and the development of distributed generation, storage and price responsive loads it is becoming increasingly important that LMP prices are used to provide an efficient price signal that energy storage and off-dispatch behind the meter resources can respond to in a manner that supports, rather than undermines, grid reliability.

This is particularly important for resources such as storage that need to optimize their output over time, charging when prices and the actual cost of power are low and injecting power when prices and the actual cost of power are higher. It is hard to imagine how storage resources could effectively compete, or realize their full potential economic value in balancing net load, in a pay-as-bid balancing market that lacks a transparent price signal, such as the real-time LMP price, to guide storage and injection decisions. This would be the case both for storage resources located in low price constrained-down regions and those located in high price constrained-up areas. In a pay-as-bid balancing market, storage resources would have to guess how low prices would be in order to submit low bids to buy at low prices and guess how high to offer in order to sell at the same price as other suppliers. If storage resources submitted bids that were too low with the hope of buying at the bid price, they could not charge, while if they submitted bids high enough to ensure they charged, they could have to pay higher prices than the cost of generation, artificially reducing the value of storage.

Conversely storage in constrained-up areas could submit offers low enough to ensure they were dispatched for balancing but would then not be paid the true market price, that is, they would not be paid the same price received by marginal resources dispatched in the balancing market to meet load at the same location. However, if they bid higher to try to be paid the market price, they would risk not being dispatched if their estimate of the market prices was slightly too high. Any pay-as-bid design based on the guessing games described above will hinder the use of storage to support an energy transition.

Moreover, single or zonal price systems will typically understate the value of ramping capability, whether provided by hydro generation, gas generation or storage resources. A single or zonal price will inherently understate the value of ramp because the non-locational prices will reflect ramping capability that is not available to balance net load in the actual dispatch because of transmission constraints.[44]

LMP markets incent and allow all resources, and all types of resources, to participate in economic dispatch to provide balancing, rather than restricting participation in the balancing market to a subset of the available resources as is the case in European balancing markets. In particular, non-LMP systems do not send a price signal that incents behind the meter resources to adjust their output in a way that balances the system. Indeed, when there is transmission congestion, non-LMP pricing systems will often incent behind the meter resources to operate in a manner that contributes to increasing local imbalances because they will operate based on the single or zonal price, rather than responding to the LMP price at their location. This role of LMP markets of supporting the broadest possible participation in balancing markets, and supporting the efficient participation of behind the meter generation, price responsive loads and price responsive network injections and withdrawals, will become more important as the level of intermittent resource output rises, and as the resource mix evolves to include more distributed resources that will respond to price signals but will not receive dispatch instructions from the system operator.[45]

The pay-as-bid pricing designs used by non-LMP balancing markets in Great Britain and the EU favor large incumbents, disadvantage both entrants and new technologies, and likely facilitate the exercise of market power by reducing the margins of small competitors. While there have been, and are, efforts to reform these designs, a large part of this discrimination is inherent in the non-locational pay-as-bid design of the balancing markets.

As we explain below, in pay-as-bid balancing markets there is no forward market in which generators and consumers in constrained regions can buy and sell forward contracts. Generators in constrained-up regions that are dispatched up in the balancing market are not paid the market clearing price and consumers whose load must be met in the balancing market do not pay the market clearing price.

2. LMP avoids need for constrained-off payments and reduces emissions

LMP pricing avoids undue payments to thermal generation that is not needed to meet load and which add emissions when operated at minimum load in order to receive constrained-off payments. LMP pricing also avoids undue payments to intermittent resources that have output profiles over the day or year that result in a significant portion of their potential output being constrained-off.

The documented experience of failure with zonal markets in the U.S. is complemented by the stunning and growing magnitude of constrained-off and on payments in Great Britain and in European zonal

44 Illustrative calculations based on the Ontario 5 minute single price and the underlying nodal price indicate that the single design reduced the profitability of faster ramping capacity by about 2/3 over 2012 for a hypothetical resource in the constrained-up region, southeastern Ontario. See Scott Harvey, “Review of the Efficiency of the Hourly Ontario Energy Price,” prepared for the IESO, July 8, 2013 pp. 139-140.

45 Conversely, limiting participation in balancing markets will benefit the incumbent resources that currently provide balancing by reducing competition.

markets that have created their own set of demands for market reform. Under non-LMP market designs, not only do consumers pay high prices for energy when it is expensive, they make high payments for suppliers in constrained-down regions to not produce under the single price designs.

3. LMP supports an efficient locational price signal

The benefits from an LMP pricing design in providing an efficient price signal applies to locating new zero emission resources, locating new storage resources, and incenting existing thermal resources to remain in operation, exit or upgrade depending on their location, capabilities, and economics.

a. Renewables

There is a growing list of assertions that the fundamental nature of renewable energy, often referred to as zero-marginal cost generation, must necessarily eliminate the need for economic dispatch and lead to a collapse of market-clearing pricing models such as the LMP system. A modest effort examining this claim reveals that the argument is simply without foundation.[46]

The implied basis of the claim is that prices will often be zero and therefore will not be sufficient to support generation investment or demand response. The claim is often that this is a self-evident fact and, therefore, we need to move beyond current electricity market designs. However, zero cost resources are not always on the margin. The Western EIM region has a high proportion of zero emission resources, but the real-time LMP prices typically are not zero. In fact, they are often far above zero. Moreover, it is not apparent that LMP prices will be zero when the energy transition is complete, because the cost of storing and withdrawing energy is not zero, the cost of pondage hydro will not be zero, the price at which price responsive loads would be willing to reduce consumption will not be zero, and the cost of hydrogen generation will not be zero. We cannot accurately foresee the resource mix that will be used to achieve net zero emission goals, but we think it fanciful to suggest that it will be achieved with prices that are always zero with no congestion.

While the results of dispatch, ancillary service provision, and so on, will certainly change with a changing resource mix, the underlying fundamentals of balancing the transmission system will remain. Even with the prospective changes in the resource mix in the U.S. and Western Europe, the price of power will not always be zero everywhere. Non–zero, and potentially quite high prices, will be needed to balance net load when intermittent resource output is low, with some of that balancing likely provided by reductions in consumption that will not occur at low prices. When intermittent resource output is very high, prices will also be needed to balance net load, perhaps in part by incenting storage both by utility scale resources and perhaps in part by decentralized devices such as the batteries of electric cars. This will be incented by appropriate locational prices. The system operator will use economic and technical inputs to coordinate a reliable economic dispatch in both situations. The associated LMP prices may be more volatile, consistent with the change in the resource mix, although the increase in volatility will be reduced as the amount of storage and price responsive load on the grid increases. But these changes

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[46] For example, see Hogan 2022.

will not eliminate the need for LMP prices that support the economic dispatch. The basic operational design of LMP markets works for all levels of marginal cost, whether high or low.

LMP incents resources to locate where they will be constrained-down less often, especially during high priced hours. States and utilities with programs subsidizing renewable resources can make use of LMP pricing to structure subsidies for low emission resources that are settled at a trading hub.[47] These designs can provide an energy price hedge for renewables, by settling the subsidy at the trading hub, rather than the generator location, but leave the consequences of siting generation in bad locations on the project, rather than shifting these costs onto power consumers as would be the case with constrained-off payments.[48] Although this has typically not been the case in the U.S., subsidy contracts could be structured as two-way contracts-for-differences which require payments by the project when the market price exceeds the contract strike price.[49] This type of contract assign avoids the potential for higher than intended subsidy payments when energy payments are high, but conversely provides a higher subsidy when prices are lower than expected. In an LMP market, subsidy contracts can also be structured so that the subsidy goes to zero if the LMP price at the trading hub is zero. LMP enables these design choices. However, subsidy design is in the hands of governments and regulators, not ISOs or RTOs.

LMP also incents developers to build resources when transmission is available, or soon will be available, to support increased output, as the resource does not generate revenues if it is put in service prior to the time there is sufficient transmission to deliver resource output to market. However, non-LMP pricing systems based on constrained-off payments incent project developers to build generation potentially years before sufficient transmission will be available to deliver the output of that generation to load, as the resource operator will receive constrained-off payments as a reward for building generation that cannot be dispatched, while consumers bear the cost of paying for resources whose output cannot be dispatched to meet load or to reduce emissions.[50]

b. Storage

In addition to shifting power production from periods with low prices to those with high prices, an important role of storage resources can be to provide ramp up and down to balance variations in

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47 See for example the Clean Path New York contract which settles a contract for differences against at a fixed average of the zone J price over the day. This design provides higher total compensation to the project if it delivers more of the renewable power in high priced hours and at locations with prices closer to the overall zone J price., see article 4 at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-e-0302&CaseSearch=Search, November 30, 2021.

48 The project operator would have the option of hedging congestion risk by purchasing an FTR from the project location to the trading hub.

49 Some subsidy contracts in Great Britain are structured this way and have required payments by projects at the current high price levels. https://www.lowcarboncontracts.uk/news/announcement/reconciliation-of-q4-2021-payments-sees-cfd-portfolio-paying-back-to-electricity-suppliers

50 The connect and manage policies in Great Britain are a conspicuous example of such a failure.

intermittent resource output. The value of ramp for balancing is typically materially understated by single price markets which maintain the fiction that all of the ramping capability on the system is available to balance net load at each location. If this were the case, there would be less need for batteries to provide ramp, but it is a fiction and a single price can greatly understate the true locational value of ramp and storage. This mispricing of ramp and storage in single clearing price markets in turn would require additional subsides to try to correct for the mispricing. Since there is no straightforward way to correct for this mispricing other than implementing an LMP market, the structure of subsidies to compensate for the under valuation of ramping capability has the likely outcome of introducing additional distortions.

LMP prices reflect the impact of transmission constraints which can greatly impact the value of ramp. The value of ramp is often low in single price markets because there is enough ramping capability across the regional or national grid to manage variations in net load. However, this ramping capability is often not actually available to balance net load because it is behind transmission constraints. Because dynamic LMP prices value power at a specific location and during a specific 5-minute interval they accurately value ramping capability at each location on the grid in each dispatch interval. This is important as it will incent storage resources to locate where storage has the most value given locational pricing patterns over the day. Storage resources could optimally be located on the constrained-down or constrained-up side of transmission constraints, depending on when the constraint is binding. LMP pricing incents storage resource operators to optimize their resource characteristics based on location and the pattern of prices over the day at that location.

c. Residual thermal generation for balancing

LMP price signal will incent balancing resources to remain in operation at the locations where they provide the most value to consumers for balancing because prices will be higher at those locations during the time periods when the output of the resources is needed, while incenting the retirement of thermal resources whose operation is no longer needed. This is not the case with non-LMP pricing designs where constrained-off payments can incent the continued operation of resources that have little value in meeting load or in providing balancing.

4. LMP allows and supports financially binding and operationally feasible day-ahead markets

With evolving resource mixes in the US, as well is in Canada, Australia, Great Britain and the EU, there will be greater operational pressure and less ability to accommodate non-LMP designs that inherently yield infeasible forward schedules. These operationally infeasible forward schedules cannot be used to balance load and generation in real-time even under expected system conditions. Moreover, reliance on infeasible forward schedules will magnify operating challenges when system conditions differ from those that were expected.

In the 1990s and 2000s operators had to manage the impact of generation and transmission forced outages that could radically change system conditions in a short period of time. These operational surprises were managed with contingency constrained economic dispatch and operating reserves that allowed the system operator to maintain reliability during those unanticipated events.

System operators still need to manage the transmission system and maintain reserves to maintain reliability following transmission and generation outages, but the pace at which system operators must manage variations in net load will potentially accelerate as the resource mix evolves. An illustrative example of this accelerated pace is that on August 15, 2020 the CAISO went from having adequate reserves, to declaring a stage 2 emergency, to shedding load in 12 minutes.[51] With operating conditions changing on an accelerated time-line in the future, there will be no room for market designs that place the system operator in a deep hole at the beginning of every operating day by starting with day-ahead market schedules that are not operationally feasible, even if there are no surprises. The conclusion we draw is that it is no longer operationally workable for system operators to rely on market designs that produce forward schedules that are inconsistent with expected market conditions.

Being able to implement an operationally feasible, and financially binding, day-ahead market was not only an important benefit of implementing on LMP market for the CAISO as discussed above, this was also an important consideration for the IESO in deciding to implement LMP for the 2020s and beyond.[52] An important driver for operationally feasible day-ahead markets in the 1990s and 2000s was the need to commit slow starting gas generating units day-ahead, so they would be available in real-time. While that need may be far less important in the 2020s and 2030s, operationally feasible day-ahead markets also provide a framework for financial schedules for price responsive load, which will need to make some decisions well before real-time; for behind the meter networks that need to take actions prior to real-time; and for other resources, such as cascade hydro systems, that may need to take costly actions day-ahead; and for storage resources to lock in margins over the day with financially binding schedules. Financially binding and operationally feasible day-ahead market schedules also provide the system operator with expected operating plans and incent the supplier to be able to operate to its schedule when needed, and to increase or reduce output relative to that schedule as dispatched based on real-time LMP prices.

5. LMP has shown itself to be flexible and able to accommodate evolving dispatch designs

Over the past 20 years LMP has accommodated a number of changes in dispatch design, all of which have readily been implemented within the overarching LMP market designs. These innovations include:

- Ramp dispatch (CAISO, Western EIM, and MISO)
- Fast start/fixed block/extended-LMP pricing (NYISO, MISO, PJM, ISO New England, SPP)
- Co-optimization of energy and ancillary services in real-time (NYISO, MISO, SPP and to some extent ISO NE and PJM)

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51 California ISO, California Public Utilities Commission, California Energy Commission, "Root Cause Analysis Mid-August 2020 Extreme Heat Wave," January 13, 2021 p. 30.

52 IESO, Market Renewal Program: Introduction to Day Ahead Market, October 11, 2017, pp. 2-9.

- Co-optimization of energy and ancillary service schedules in the day-ahead market (all U.S. ISOs)
- Reserve shortage pricing NYISO, MISO, PJM, ISO NE, PJM, SPP and ERCOT
- Multiple interval optimization (CAISO, Western EIM and NYISO)
- 15 minute pricing and settlements as well as 5 minute pricing (CAISO, Western EIM)
- Transmission overload pricing (NYISO, CAISO, MISO, SPP, and ERCOT.

We have focused in this paper on economic dispatch and LMP pricing, but there has also been an evolution and innovation of financial transmission right auction design to meet the evolving needs of market participants. These changes include implementation of:

- On- and off-peak FTRs
- Balance of period auctions (PJM, MISO, NYISO and ISO New England)
- Future year auctions (PJM, ERCOT and NYISO)
- Transmission outage performance incentives (NYISO)

Moreover, there are additional innovations on the horizon which can also be readily implemented within an LMP framework

- State of Charge based storage offers and dispatch (CAISO)
- Financially binding, operationally feasible, intra-day markets

It is not clear how state of charge-based bidding could even be workable in pay-as-bid balancing markets that require participants to bid the market price in order to be paid the same market price that the marginal supplier is paid. This is another example of how pay-as-bid balancing mechanisms are wedded to the past. Pay-as-bid designs are always inefficient and discriminatory but they are particularly unsuited to managing the output of the evolving resource mix and a transmission grid that may rely to a significant extent on distributed resources for balancing.

Similarly, it would not be possible to introduce operationally feasible and financially binding intra-day market without LMP for much the same reason that operationally feasible day-ahead markets are not workable in single clearing price markets.

Finally, we noted above the potential benefits in subsidy design from the use utilities and states are making of LMP pricing in the structure of subsidy contracts for low or zero emission resources to incent efficient locational and operating decisions by structuring the subsidies as a CFD settling at a trading hub or zonal price.

V. Conclusion

LMP pricing puts US markets in a better position to accommodate rising levels of intermittent output than would be the case with single or zonal pricing designs. Moreover, one underlying concern of commentators with LMP markets is with the level of payments to renewable resources when energy prices are high. As we have pointed out above, the level of these payments is an outcome of state and federal policies, not ISO and RTO pricing designs. Moreover, the ability of LMP markets to obviate the need for constrained-off payments to manage congestion is particularly important when market clearing prices are high due to high fuel costs as is the case today both in the US, and around much of the world, and these “payments to not produce” would also rise.

There are still huge operational and market challenges in accommodating higher levels of intermittent output while maintaining historical levels of reliability, but LMP pricing contributes to achieving this goal. Market designs based on command and control, constrained-on and-off payments and pay-as-bid balancing mechanisms will at best hinder achieving these goals, if not make it impossible without adverse impacts on reliability. Critical operational benefits of LMP market designs in maintaining reliability with the evolving resource mix include:

- An efficient, transparent price signal for storage resources, behind the meter generation, price responsive loads and behind the meter networks, enabling these resources to support grid reliability during stressed system conditions rather than undermining it;
- Operationally feasible, financially binding, day-ahead market schedules that posture the system to meet expected system conditions, schedule the resources needed to balance net load during unexpected conditions, and incent resources to be available to cover their schedules in real-time.
- Efficient locational incentives that not only reduce consumer costs but also support transmission grid reliability by providing efficient incentives for the locational supply of storage and ramping capability;
- Avoiding the consumer cost of constrained-off payments, associated with single and zonal price market designs;
- Supporting efficient and competitive entry to provide balancing by enabling forward hedging at locational prices that reflect transmission congestion and enable sale of exchange traded forward contracts supported by balancing capability;
- The ability to accommodate new concepts in dispatch design and the continued evolution of environmental rules and subsidies, including possible improved designs which reduce subsidies as market prices rise; and
- The ability of LMP pricing designs to accommodate market power mitigation designs that are focused on sellers with the ability to profitably exercise locational market power without confounding market power with pay-as-bid incentives.

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EndNote

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