



HAL
open science

Incremental wind energy development in the Midcontinent Independent System Operator electricity markets of the United States

Han Qi, Kang Hua Cao, Chi Keung Woo, Raymond Li

► **To cite this version:**

Han Qi, Kang Hua Cao, Chi Keung Woo, Raymond Li. Incremental wind energy development in the Midcontinent Independent System Operator electricity markets of the United States. *The journal of energy markets*, 2023, 16 (2), pp.29-53. 10.21314/JEM.2023.024 . hal-04338633

HAL Id: hal-04338633

<https://hal.science/hal-04338633>

Submitted on 12 Dec 2023

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.

Incremental wind energy development in the Midcontinent electricity markets of the US

H.S. Qi^{a,*}, K.H. Cao^b, C.K. Woo^c, R. Li^d

- ^a Shenzhen Audencia Financial Technology Institute, Shenzhen University, Guangdong, People's Republic of China (steffan@szu.edu.cn)
- ^b Department of Accountancy, Economics and Finance, Hong Kong Baptist University, Hong Kong, People's Republic of China (kanghuacao@hkbu.edu.hk)
- ^c Centre for Sustainable Development Studies, Hong Kong Baptist University, Hong Kong, People's Republic of China (chikeungwoo5@gmail.com)
- ^d Canberra School of Politics, Economics & Society, University of Canberra, Australian Capital Territory, Australia (raymond.li@canberra.edu.au)

* Corresponding author

Figures and Table legends

Table 1 Descriptive statistics of hourly data

Table 2 Regression results by region and market type

Table 3 Results for the extent of incremental wind energy development

Table 4 Response analysis of the extent of incremental wind energy development based on the OLS regression specification

Figure 1 MISO's footprint and local resource zones

Abstract

This paper projects how much incremental wind energy development (WED) may occur without causing inadequate investment incentives (*aka* missing money) for wind generation and natural-gas-fired generation in the day-ahead market (DAM) and real-time market (RTM) of the Midcontinent Independent System Operator (MISO) in the US. Using a large sample of hourly data for the 82-month period of 01/01/2014 - 10/31/2020, it documents that the DAM's hourly investment incentives move with (a) the day-ahead forecast of daily natural gas price; (b) MISO's day-ahead hourly requirements of ancillary services; (c) MISO's zonal day-ahead hourly schedules of nuclear generation, wind generation, and must-run generation; and (d) MISO's zonal day-ahead forecasts of hourly loads. Findings based on the RTM's hourly data tell a similar story. Further, the negative effect of incremental WED on investment incentives over the forward-looking period of 2023-2042 is offset by the positive effect of rising natural gas price, nuclear plant retirement, declining must-run generation, and growing demand. In the extreme case of nuclear plant retirement and zero must-run generation, incremental WED of up to ~441% of the existing wind generation level may occur as a market-based outcome without missing money in MISO's DAM.

Keywords: Wind energy development, generation investment incentives, missing money, Midcontinent electricity markets, United States

Key messages

- Analyse profitability of wind power purchasing agreements and tolling agreements
- Estimate incremental wind energy development (WED) for the 2023-2042 period
- Find incremental WED of up to 441% without causing inadequate generation investment incentives
- Conclude that market forces alone may suffice to induce large-scale incremental WED

Incremental wind energy development in the Midcontinent electricity markets of the US

1. Introduction

At the 2021 G20 Summit held in Rome, the United States (US) reaffirmed its deep decarbonization commitment to tackle the urgent threat of climate change,¹ necessitating large-scale wind energy development (WED) (Williams et al., 2012, 2014; Mahone et al., 2018).² Thanks to declining wind capacity costs (Wiser et al., 2021) and government policies of renewable portfolio standards, investment and production tax credits, and easy transmission access (Alagappan et al., 2011; Hitaj, 2013), WED in the US has been explosive, as evidenced by the vast increase in total installed wind capacity from ~1 GW in 2010 to ~122 GW in 2020.

An electric grid in the US can accommodate the rising market penetration of wind generation (WG) with transmission expansion (Joskow, 2021) and flexible capacity provided by natural-gas-fired generation (NG), demand response resources, and energy storage systems (Hargreaves et al., 2015). With a feature like capacity market (Spees et al., 2013), resource adequacy requirement (Cramton, 2017), or regulatory price adder (Zarnikau et al., 2020a), the grid's wholesale market design mitigates NG's missing money problem of inadequate investment incentive (Joskow, 2013), which is further exacerbated by WG's electricity price reduction (*aka* merit order) effect (Woo et al., 2012, 2016; Quint and Dahlke, 2019; Zarnikau et al., 2019, 2020b; Prol et al., 2020; Peña et al., 2022).

As the regional transmission organization (RTO) in the US Midwest, the Midcontinent Independent System Operator (MISO) uses locational marginal pricing (Stoft, 2002) and 10 local resource zones (LRZs) shown in Figure 1 for determining the hourly prices for energy

¹ <http://www.g20.utoronto.ca/2021/G20ROMELEADERSDECLARATION.pdf>

² Other decarbonization measures include solar energy development, energy efficiency improvement, conservation, and implementation of smart grid aided by advanced metering infrastructure that enables dynamic pricing and reliability differentiation (Woo and Zarnikau, 2019; Woo et al., 2019).

and ancillary services in its day-ahead market (DAM) and real-time market (RTM) (Zarnikau et al., 2020b). This paper empirically answers the substantive research question of how much incremental WED may occur as a market-based outcome without missing money for WG's and NG's investments.

This question is real-world relevant, underscored by WG's and NG's documented missing money problem (Woo et al., 2012, 2016, 2019; Woo and Zarnikau, 2019; Prol et al., 2020; Cao et al., 2021; Peña et al., 2022) that dims the prospect of relying on market-based incentives to maintain system reliability (Joskow and Tirole, 2007; Joskow, 2013). It is also policy important because incremental WED weakens the investment incentives for WG and NG that have lower CO₂ emissions than coal-fired generation plants owned by MISO's members (Zarnikau et al., 2020b). Further, NG's flexible capacity is necessary for MISO's integration of the rising market penetration of WG (Hargreaves et al., 2015). Finally, an assessment of incremental WED's effects on generation investment incentives reveals the factors that can mitigate the missing money problem (Mills et al., 2015).

There are three reasons justifying our focus on MISO. First, "MISO operates one of the world's largest energy markets with more than \$40 billion in annual market energy transactions."³ Second, MISO's service territory in the US comprises the Northern region of LRZs 1 to 7 and the Southern region of LRZs 8 to 10. As shown by Figure 1, these two regions are geographically distinct, thus enabling an empirical analysis of regional generation investment incentives. Finally, MISO has salient features that make our paper an important and interesting case study, including its large footprint, huge peak demand, diverse market participants, and mix of heterogeneous generation capacities (Zarnikau et al., 2020b; Cao et al., 2021).⁴

³ <https://www.misoenergy.org/about/media-center/corporate-fact-sheet/>

⁴ According to its 2022 corporate fact sheet (<https://www.misoenergy.org/about/media-center/corporate-fact-sheet/>), MISO has a total generation capacity of 205.2 GW, historic summer peak of 127.1 GW set on 07/20/2011, historic winter peak of 109.3 GW set on 01/06/2014, membership of 56 transmission owners and

Based on the hourly data for the 82-month period of 01/01/2014 to 10/31/2020 used by Cao et al. (2021) to determine MISO's energy trading efficiency, our key findings are:

- (1) Rising market penetration of WG shrinks WG's and NG's regional investment incentives in MISO's DAM and RTM.
- (2) MISO's regional generation investment incentives increase with rising natural gas price, declining must-run generation,⁵ growing demand, and declining nuclear generation.
- (3) The projected negative effect of incremental WED on MISO's regional generation investment incentives in the forward-looking period of 2023-2042 is offset by the projected positive effect of the factors listed in (2).
- (4) In the extreme case of nuclear plant retirement and zero must-run generation, incremental WED of up to ~441% may occur as a market-based outcome without missing money in MISO's DAM.

Our paper makes three contributions that complement recent empirical studies of missing money due to WG's merit order effect (e.g., Quint and Dahlke, 2019; Zarnikau et al., 2019, 2020b; Prol et al., 2020; Cao et al., 2021; Peña et al., 2022):⁶

- It adopts the perspective of a cost-minimizing load serving entity (LSE) (Woo and Zarnikau, 2019; Woo et al., 2019), leading to a newly developed explanation of the missing money problem based on the profitability of a wind power purchase agreement (WPPA) and a tolling agreement (TA). This explanation matches (a) the business reality

134 non-transmission owners, and generation capacity mix of natural gas (43%), coal (27%), renewables (21%), nuclear (7%) and other (2%).

⁵ With a zero price offer, must-run generation is the amount of electricity to be dispatched by MISO before supplies with positive price offers. Its presence is attributable to such reasons as (1) thermal power plants fueled by coal and natural gas often have minimum output requirements; (2) nuclear power plants are baseload and largely non-dispatchable; and (3) an integrated electric utility under the cost-of-service regulation may prefer to use its own generation assets instead of wholesale market purchases to meet its retail load obligations. As an increase in must-run generation causes a rightward shift of MISO's generation supply curve, it reduces MISO's wholesale electricity prices (Zarnikau et al., 2020a).

⁶ Two reasons support our paper's exclusion of a comprehensive literature review of the numerous studies on renewable energy's merit order effect that diminishes generation investment incentives. First, such a review does not add material insights beyond those presented herein. Second, ample literature reviews are already available in the cited papers, thus obviating our duplication of effort.

that a power plant developer in the US often uses such agreements to obtain project financing at a reasonable cost (Stern, 1998); and (b) the widespread use of WPPAs that suggests windfarm owners seldom make supply offers like independent power producers of conventionally generated energy in a RTO's DAM and RTM.

- To the best of our knowledge, it is the first empirical study of regional generation investment incentives in MISO's DAM and RTM. Specifically, it documents what matters in MISO's incremental WED, thus complementing the assessment studies by Mills et al. (2015, 2020).
- Its regression-based approach is applicable to assess incremental WED's effects on generation investment incentives in the wholesale electricity markets operated by other RTOs in North America, as well as those in Europe (e.g., France, Germany, Italy, Spain, and UK), South America (e.g., Brazil and Chile), and Asia Pacific (e.g., Australia, New Zealand, and Singapore).

The rest of this paper proceeds as follows. Section 2 explains WG's and NG's investment incentives. Section 3 develops our regression setup. Section 4 assesses how much incremental WED may occur as a market-based outcome for the 2023-2042 period. Section 5 reports our empirics, the basis for Section 6: conclusions and policy implication.

2. Generation investment incentive based on a LSE's least-cost procurement

We use $E(\pi)$ = expected annual sum of hourly operating profits per MW of installed capacity to measure generation investment incentive (Woo et al., 2012, 2016). If $E(\pi) \geq F =$ per MW installed cost (\$) \times [cost of capital (% per year) + depreciation (% per year)], there is adequate investment incentive. When $E(\pi) < F$, the missing money problem is said to exist.

We calculate hourly operating profit from the perspective of a LSE that minimizes its energy procurement cost (Woo and Zarnikau, 2019; Woo et al., 2019; Cao et al., 2023). This makes sense based on the following line of reasoning. After signing a 1-year WPPA at

levelized price $LP = \sim \$25/\text{MWh}$ (Wiser et al., 2021),⁷ each wind MWh delivered in hour $h = 1, \dots, 24$ on day d displaces the same amount to be bought at wholesale market spot price P_{dh} . As a result, P_{dh} is the LSE's per MWh avoided energy cost attributable to the signed WPPA.

Made possible by the signed WPPA, $\pi_{dh} = P_{dh} - LP$ is the LSE's per MWh profit in hour h on day d . When the annual sum of $E(\pi_{dh}) > 0$, it induces the LSE to sign the WPPA. As WG's merit order effect reduces $E(P_{dh})$, it diminishes the LSE's signing incentive.

We now consider the case of a 1-year TA for a MW-share of a dispatchable and fast ramping NG plant that employs combined cycle gas turbines (CCGTs). After signing the TA with contracted heat rate HR (MMBtu/MWh), the LSE instructs the plant operator to perform economic dispatch to achieve $C_{dh} = \min(P_{dh}, HR \times G_d)$, where $G_d =$ natural gas price ($\$/\text{MMBtu}$) on day d (Woo et al., 2016, 2019). As a result, C_{dh} is the LSE's per MWh procurement cost in hour h on day d .

The LSE's hourly profit in hour h on day d is $(P_{dh} - C_{dh} - K)$, where $K =$ per MWh fixed charge $=$ TA's per MW-year capacity cost for a CCGT \div 8,760 hours per year $= \sim \$11.41/\text{MWh}$ (PJM, 2018). When the annual sum of $[E(P_{dh}) - E(C_{dh}) - K] > 0$, it induces the LSE to sign the TA. As WG's merit-order effect reduces $[E(P_{dh}) - E(C_{dh})]$ (Woo et al., 2016), it diminishes the LSE's signing incentive.

In summary, the rising market penetration of WG tends to reduce the construction of windfarms and NG plants in wholesale electricity markets like those operated by MISO. Section 3 below proposes a regression analysis of the hourly data for P_{dh} and C_{dh} to reveal the factors that can offset this capacity reduction. Section 4 then uses the regression results to assess the market-based incremental WED in MISO's DAM and RTM.

⁷ Without any loss in generality, the 1-year contract period is assumed solely for expositional clarity and simplicity.

3. Regression setup

3.1 Specification

For expositional ease, we first focus on MISO's DAM in the Northern region, as the discussions in connection to MISO's DAM in the Southern region and RTMs in both regions are entirely analogous.

Let P_{jdh} = hourly DAM price of LRZ $j = 1, \dots, 7$ in hour $h = 1, \dots, 24$ on day $d = 01/01/2014, \dots, 10/31/2020$. The data generating process (DGP) for P_{jdh} is assumed to be the following linear regression with random error ε_{jdh} that may be heteroskedastic and autocorrelated:

$$P_{jdh} = \mathbf{X}_{jdh} \boldsymbol{\beta} + \text{fixed effect} + \varepsilon_{jdh}, \quad (1)$$

where \mathbf{X}_{jdh} = vector of fundamental drivers; $\boldsymbol{\beta}$ = vector of coefficients that measure the marginal price effects of \mathbf{X}_{jdh} ; and fixed effect = linear function of the intercept and binary indicators for time of the day, day of the week, month of the year, and LRZs in MISO's Northern region. We decide not to use the log-linear specification, chiefly because the presence of negative prices renders $\ln(P_{jdh})$ undefined.⁸

Guided by Zarnikau et al. (2020b) and Cao et al. (2021), the regressors in equation (1) are as follows:⁹

- X_{1dh} = Daily forecast of natural gas price (\$/MMBtu) at the Henry Hub that does not vary hourly.¹⁰ Its coefficient $\beta_1 > 0$ measures the DAM price effect of a \$1/MMBtu increase in natural gas price.

⁸ During low-demand hours (e.g., 02:00 to 05:00), MISO's system loads at times cannot fully absorb the non-dispatchable generation output from nuclear plants and windfarms. To maintain its load-resource balance, MISO uses negative prices to induce generation curtailment by dispatchable NG plants in these hours.

⁹ Thanks to a diligent referee's insightful comment, we exclude the PJM price for energy at the MISO-PJM border as a regressor because it is highly colinear with the natural gas price.

¹⁰ The following reasons support our use of the Henry Hub price (Woo et al., 2006a): (a) Henry Hub is the largest trading hub in the US; (b) the Henry Hub is the delivery point of the US natural gas futures; (c) the Henry Hub price is highly correlated ($r > 0.9$) with local hub prices in MISO's service territory; and (d) the Henry Hub price is exogenously determined by the national integrated market formed by interconnected markets across the US.

- X_{2dh} = MISO's system AS requirement (MW) announced on day $d-1$ for hour h on day d . Its coefficient $\beta_2 > 0$ measures the DAM price effect of rising AS requirement.
- X_{3jdh} = LRZ j 's local wind MWh scheduled on day $d-1$ for delivery in hour h on day d . Its coefficient $\beta_3 < 0$ measures the DAM price effect of LRZ j 's rising WG.
- X_{4jdh} = Total non-local wind MWh of **all** other LRZs scheduled on day $d-1$ for delivery in hour h on day d . For example, if $j = 1$, X_{4jdh} = sum of wind MWh for LRZs 2 to 7 because LRZs 8 to 10 do not have WG. Its coefficient $\beta_4 < 0$ measures the DAM price effect of rising WG in all other LRZs.
- X_{5jdh} = LRZ j 's local nuclear MWh scheduled on day $d-1$ for delivery in hour h on day d . Its coefficient $\beta_5 < 0$ measures the DAM price effect of LRZ j 's rising nuclear generation.
- X_{6jdh} = Total non-local nuclear MWh of all other LRZs scheduled on day $d-1$ for delivery in hour h on day d . Its coefficient $\beta_6 < 0$ measures the DAM price effect of rising nuclear generation in all other LRZs.
- X_{7jdh} = LRZ j 's local must-run MWh scheduled on day $d-1$ for delivery in hour h on day d . Its coefficient $\beta_7 < 0$ measures the DAM price effect of LRZ j 's rising must-run generation.
- X_{8jdh} = Total non-local must-run MWh of all other LRZs scheduled on day $d-1$ for delivery in hour h on day d . Its coefficient $\beta_8 < 0$ measures the DAM price effect of rising must-run generation in all other LRZs.
- X_{9jdh} = LRZ j 's forecast of local MWh load made on day $d-1$ for hour h on day d . Its coefficient $\beta_9 > 0$ measures the DAM price effect of LRZ j 's rising demand.
- X_{10jdh} = Forecast of non-local MWh load of all other LRZs made on day $d-1$ for hour h on day d . Its coefficient $\beta_{10} > 0$ measures the DAM price effect of rising demands in all other LRZs.

We now turn our attention to the per MWh procurement cost regression. Based on Woo et al. (2016), we assume $HR = 7$ MMBtu per MWh = engineering-based heat rate of a CCGT, the most popular thermal generation technology deployed in the US. If an LSE serving LRZ j has signed a CCGT-based TA, its day-ahead per MWh procurement cost is $C_{jdh} = \min(P_{jdh}, 7 \text{ MMBtu per MWh} \times \$X_{1dh} \text{ per MMBtu})$, as the TA's per MWh non-fuel variable cost is for all practical purposes negligible (Woo et al., 2016).

The DGP for C_{jdh} is assumed to be the following linear regression with the coefficient vector γ that measures the marginal cost effects of X_{jdh} and random error μ_{jdh} that may be heteroskedastic and autocorrelated:

$$C_{jdh} = X_{jdh} \gamma + \text{fixed effect} + \mu_{jdh}. \quad (2)$$

As the regression specification for the Northern region's DAM, equations (1) and (2) show that P_{jdh} and C_{jdh} move in tandem because (a) they both use $\{X_{jdh}\}$ as their fundamental drivers; and (b) the marginal effects of X_{jdh} on C_{jdh} based on γ in equation (2) mimic those on P_{jdh} based on β in equation (1). A case in point is that a \$1/MMBtu increase in natural gas price is expected to raise C_{jdh} by $\$ \gamma_1/\text{MWh}$ and P_{jdh} by $\$ \beta_1/\text{MWh}$.

Replacing their regressands and regressors to reflect the Southern region's DAM yields two additional equations to be estimated. Further, replacing the day-ahead data with real-time data leads to four equations for the two regional RTMs. In short, each region has a system of two energy price regressions and two per MWh procurement cost regressions differentiated by market type.

3.2 Estimation strategy

Recall the two regional regression systems in Section 3.1, the Northern system, which uses hourly data for LRZs 1 to 7, and the Southern system, which uses hourly data for LRZs 8 to 10. As the two regional systems have unequal sample sizes, we use PROC MODEL of

SAS to estimate them separately.¹¹ We use PROC MODEL's GMM option to obtain heteroscedasticity-autocorrelation-consistent (HAC) standard errors for gauging the statistical significance of the coefficient estimates (Wooldridge, 2010).¹² Finally, we perform unit root tests to allay the concern of spurious regressions caused by non-stationary regression residuals (Davidson and MacKinnon, 1993).

4. Incremental wind energy development

4.1 Wind power purchase agreement

Stated below are the steps for assessing how much incremental WED may occur without reducing a WPPA's profitability in MISO's DAM over the 2023-2042 period.

Step 1 uses the regional DAM price regression results to calculate $\Delta R > 0$, the regional average of hourly DAM price increases triggered by the plausible events listed below:

- (1) \$1/MMBtu increase in the Henry Hub natural gas price in the 20-year period. The Henry Hub price is expected to rise because of (a) increasing US export of LNG to reduce Europe's dependence on Russia's supply of natural gas (EIA, 2022); (b) a slowdown in shale gas development due to environmental concerns about hydraulic fracturing (Sovacool, 2014); (c) electricity generation's increasing demand for natural gas based on the EIA's Annual Energy Outlook 2022;¹³ and (d) inter-fuel substitution between natural gas and petrol products like fuel oil and diesel (Li et al., 2022).
- (2) Nuclear plant retirement. As the nuclear plants in MISO's service territory are over 20 years old, their retirement may occur by the end of the 2023-2042 period. Thus, we calculate ΔR under two assumptions: (a) without nuclear retirement; and (b) with nuclear retirement.

¹¹ <https://support.sas.com/documentation/onlinedoc/ets/132/model.pdf>

¹² <https://support.sas.com/kb/40/098.html>

¹³ https://www.eia.gov/outlooks/aeo/pdf/AEO2022_ReleasePresentation.pdf

- (3) Cumulative load growth of 20% for the 20-year period. It is based on the annual forecast of ~1% per year in the EIA's Annual Energy Outlook 2022.
- (4) Reduction in must-run generation, reflecting the possibility of the rising volume of supply offers with strictly positive price quotes submitted by thermal generators during MISO's market operation hours. This possibility arises due to the retirement of aging power plants with relatively low operational flexibility and high CO₂ emissions (e.g., coal-fired power plants) and the construction of new power plants with relatively high operational flexibility and low CO₂ emissions (e.g., CCGTs). Since we cannot accurately project the extent of this reduction in the 20-year period, we assume hypothetical reductions of 0%, 25%, 50%, 75%, and 100%.

Step 2 assumes λ = total percentage increase in day-ahead wind MWh by LRZ at the end of the 20-year period. For illustration, the day-ahead wind MWh in the year 2042 for LRZ 1 in MISO's Northern region is $(1 + \lambda) \times$ LRZ 1's day-ahead wind MWh in 2019. We select 2019 as the reference year because it is the most recent year in our sample period, with hourly data for all 12 calendar months.

Step 3 uses the DAM price regression results to calculate $\Delta S < 0$, which is WG's regional average of hourly DAM price reductions based on λ 's assumed value.

Step 4 varies λ from 1% to 500% to find λ^* that results in $\Delta R + \Delta S = 0$. Hence, λ^* is an estimate for the market-based extent of incremental WED in connection to WPPAs. As there is no local wind generation in the Southern region, we use the Northern region's wind MWh to determine the λ^* values for both regions.

To find the regional λ^* values for the RTM, we repeat Steps 1 to 4 after replacing the DAM price regression results with the RTM price regression results and the day-ahead data with the real-time data.

4.2 Tolling agreement

Stated below are the steps for assessing how much incremental WED may occur in connection to TAs in MISO's DAM over the 2023-2042 period:

Step 1 uses the regional DAM price and per MWh procurement cost regression results to calculate $\Delta R'$ = regional average of hourly $\Delta(P_{jdh} - C_{jdh})$ = TA's projected per MWh profit increase due to the events listed in Step 1 of Section 4.1.

Step 2 assumes λ = total percentage increase in day-ahead wind MWh by LRZ at the end of the 20-year period.

Step 3 uses the regression results noted in Step 1 to calculate $\Delta S' < 0$, which is the TA's decremental per MWh profit. Specifically, $\Delta S'$ = regional average of hourly $\Delta(P_{dh} - C_{dh})$ based on λ 's value assumed in Step 2.

Step 4 varies λ from 1% to 500% to find λ^{**} that results in $\Delta R' + \Delta S' = M$, where M = NG's amount of missing money embodied in the existing hourly data.

To find λ^{**} for the RTM, we repeat Steps 1 to 4 after replacing the DAM price and per MWh procurement cost regression results with their RTM counterpart and the day-ahead data with the real-time data.

4.3 Extent of incremental WED

Since wind capacity expansion simultaneously affects a WPPA's and a TA's profitability, $\lambda_M = \min(\lambda^*, \lambda^{**})$ is the condition for adequate investment incentives for WG *and* NG. This makes sense because λ_M is the extent of incremental WED that may occur without causing missing money for WG and NG (Woo et al., 2023).

5. Empirics

This section reports our empirics based on MISO's hourly data from 01/01/2014 to 10/31/2020. After describing the hourly data, it presents our regression results, followed by our assessment of incremental WED for the forward-looking period of 2023-2042.

5.1 Descriptive statistics and correlations

Table 1 presents our hourly data's descriptive statistics and correlations, leading to the following remarks. The mean energy prices are between \$26 and \$28/MWh, higher than the LP of a 1-year WPPA of ~\$25/MWh recently reported by Wiser et al. (2021). As the WPPA's LP presumably fully covers WG's fixed costs, there is adequate investment incentive for a windfarm developer and sufficient signing incentive for a LSE.

The mean per MWh procurement costs are between \$19 and \$20/MWh. As a result, a 1-year TA's mean payoff is between \$7.55/MWh to \$8.07/MWh based on the average difference between energy prices and per MWh costs. Since a CCGT's per MWh capacity cost is ~\$11.41/MWh (PJM, 2018), the TA's amount of missing money is $M = \sim \$4/\text{MWh}$ used in Step 4 of Section 4.2.

The average energy price and per MWh procurement cost are slightly higher in the Northern region's DAM than in RTM. However, they are lower than the corresponding averages of the Southern region. Further, energy prices and the differentials between energy price and per MWh procurement cost for both regions are highly volatile, as evidenced by their wide ranges and large standard deviations. Finally, per MWh procurement costs are less volatile than energy prices because of a CCGT's economic dispatch based on the relatively stable natural gas prices.

Regional energy prices are positively correlated with per MWh procurement costs ($r > 0.33$) and natural gas price ($r > 0.28$). However, they are weakly correlated with regional wind generation, nuclear generation, load, and must-run generation.

Regional per MWh procurement costs positively correlate with natural gas price ($r > 0.74$). As in the case of energy prices, they are weakly correlated with regional wind generation, nuclear generation, load, and must-run generation.

While the correlations generally corroborate our expectations, they do not untangle the marginal effects of each fundamental driver on energy prices and procurement costs, thus motivating our use of the regression results presented in the following section.

5.2 Regression results

Table 2 reports the regression results that yield the following inferences:

- The adjusted R^2 values are between 0.261 and 0.826 for the Northern region and 0.172 and 0.984 for the Southern region. As the low 0.261 and 0.172 values come from the two regional RTM price regressions, the remaining six regressions are deemed to have a reasonable fit.
- The slope coefficient estimates generally support our expectation of the price and cost effects of the fundamental drivers because only 7 out of the 76 estimates have unexpected signs and are statistically significant.
- A \$1/MMBtu increase in daily natural gas price tends to increase the Northern region's DAM energy price by \$6.6/MWh and RTM energy price by \$4.9/MWh. Its impact on the Southern region's DAM and RTM energy prices are \$7.5/MWh and \$7.6/MWh. Reflecting the energy price regressions' empirical plausibility, these estimated effects equal NG's market-based marginal heat rates that in the main are numerically close to a CCGT's engineering-based heat rate of 7 MMBtu/MWh. The responses of per MWh procurement costs to a \$1/MMBtu increase in natural gas price are similar to those of DAM and RTM energy prices in both regions.
- The statistically significant estimated effects of a 1-GW increase in system AS requirement on energy prices and per MWh procurement costs are \$0.436/MWh to \$3.457/MWh.
- Confirming WG's merit order effects, each additional GWh of local wind generation in the Northern region tends to reduce the region's energy prices and per MWh procurement

costs by \$0.79/MWh to \$2.73/MWh, larger than the reductions due to non-local WG's increase of the same amount.

- The estimated impacts of a 1-GW increase in the local nuclear generation on energy price are -\$0.03/MWh to -\$3.70/MWh, larger in size than those of a 1-GW increase in non-local nuclear generation.
- The estimated marginal effects of 1-GW increases in local and non-local must-run generation on energy prices in both regions are mixed and less than \$1.21/MWh in size.
- Rising local and total non-local GWh loads tend to have positive impacts of \$0.562 to \$3.031/MWh on energy prices and \$0.012 to \$0.129/MWh on per MWh procurement costs in the DAM and RTM of both regions.

When taken together, the preceding findings lend support for using Table 2 to quantify the incremental WED estimates presented below.

5.3 Incremental WED estimates

Under the assumption of no nuclear plant retirement, the top half of Table 3 reports that the Northern region's λ_M estimates range from 190% to 267%. Nuclear plant retirement would greatly magnify these estimates. Finally, the λ_M estimates for the Southern region are below those for the Northern region.

To better understand what drives Table 3's voluminous results, we estimate the following OLS regression with intercept α and random error η :

$$Y = \alpha + \nu N + \phi MG + \rho R + \delta D + \eta, \quad (3)$$

where $Y = \lambda_M$ estimate in Table 3; $N = 1$ if nuclear plant retirement, 0 otherwise; $MG =$ percentage reduction in must-run generation; $R = 1$ if Southern region, 0 otherwise; and $D = 1$ if RTM, 0 otherwise.

Equation (3)'s slope coefficients untangle the effects of N , MG , R , and D on λ_M , thus revealing what matters in MISO's market-based incremental WED. To see this point,

consider the case of $N = MG = R = D = 0$ so that the expected value of Y is $E(Y) = \alpha$, which is the Northern region's average λ_M value based on the DAM data in the absence of nuclear retirement and must-run generation reduction. Suppose $N = 1$ that indicates nuclear plant retirement that results in $E(Y) = (\alpha + \nu)$. Hence, ν is nuclear plant retirement's effect on the Northern region's average λ_M value. If ν 's estimate is large, nuclear plant retirement is expected to greatly increase MISO's incremental WED for 2023-2042.

Table 4 reports the OLS regression results that lead to the following inferences:

- The regression has an adjusted R^2 is 0.97. With the exception of D , it has highly significant (p -value < 0.01) coefficient estimates for the remaining regressors. Hence, it is a reasonable characterization of the λ_M estimates reported in Table 3.
- The sample mean of the λ_M estimates is 213%, presaging the potentially large level of incremental WED in MISO's DAM and RTM.
- For the scenario of $N = MG = R = D = 0$, the λ_M estimate is 223%, chiefly reflecting the combined effect of the \$1/MMBtu increase in natural gas price and MISO's cumulative growth of 20% by the end of 2042.
- Nuclear plant retirement increases the λ_M estimates by 118%, making it the biggest driver of MISO's incremental WED.
- A 1% reduction in must-run generation is found to increase the λ_M estimates by 0.54%. Should the must-run generation become zero, the resulting increase would be 54%.
- The Northern region's λ_M estimates are on average 180% above the Southern region's.
- The DAM's λ_M estimates are on average 13% (p -value = 0.052) above the RTM's.

Table 4's overall message is that large-scale incremental WED may occur as a market-based outcome in MISO's DAM and RTM, due chiefly to the projected increases in natural gas price, load growth, nuclear plant retirement, and decline in must-run generation.

6. Conclusions and policy implication

Our conclusions are: (a) hourly generation investment incentives in MISO's DAM and RTM move with their fundamental drivers; (b) incremental WED's negative effects on generation investment incentives for the forward-looking period of 2023-2042 are offset by positive effects of rising natural gas price, nuclear plant retirement, declining must-run generation, and growing electricity demand; (c) incremental WED without causing missing money for WG and NG can be as much as 441% in the extreme case of nuclear plant retirement and zero must-run generation; and (d) the regression results shown in Table 4 delineate what matters in the assessment of MISO's market-based WED. The overall policy implication of these conclusions is that market forces alone may suffice to induce large-scale incremental WED in MISO's DAM and RTM.

We would be remiss had we failed to acknowledge the following caveats of our paper. First, as our regression-based approach necessarily uses historical hourly data, it cannot determine the changes in generation investment incentives due to significant events that may occur beyond our sample period (e.g., a substantial revision of MISO's wholesale product mix and expansion of transmission interconnection between MISO's Northern and Southern regions). Nevertheless, its empirics can be readily updated with additional data collection.

Second, our regression setup in Section 3 may be considered inadequate when compared to time series modeling of market prices that exhibit long memory and regime switching (Haldrup and Nielsen, 2006; Karakatsani and Bunn, 2008; Janczura and Weron, 2010) and engineering simulation of WED's impact on locational marginal prices (Morales and Conejo, 2011). That said, our regression setup is meritorious in providing a first look at incremental WED without missing money in MISO's DAM and RTM.

Finally, our paper overlooks the numerous thorny issues that can limit the ability of a RTO like MISO to deliver reliable service at stable prices (Woo et al., 2003, 2006b) that obey the principles of least-cost resource planning, procurement, and operation (Woo et al., 2019).

A partial list of these issues includes wholesale market's trading inefficiency, transmission congestion, market power abuse, inadequate use of reliability differentiation and dynamic pricing at the retail level, retail pricing's limited pass-through of wholesale price changes, market power abuse by rogue independent power generators, and poor coordination of generation and transmission investments in a competitive market environment (Cao et al., 2021). While meaningfully addressing some of these issues is possible through a market design with reliability differentiation and generation dispatch based on marginal fuel costs (Woo et al., 2019), it is well beyond this paper's intent and scope.

Declarations of Interest

The authors report no conflicts of interest. The authors alone are responsible for the content and writing of the paper.

References

- Alagappan, L., Orans, R., and Woo, C.K. (2011). What drives renewable energy development? *Energy Policy* **39**, 5099-5104.
(DOI: <https://doi.org/10.1016/j.enpol.2011.06.003>)
- Cao, K.H., Qi, H.S., Tsai, C.H., Woo, C.K., and Zarnikau, J. (2021). Energy trading efficiency in the US Midcontinent electricity markets. *Applied Energy* **302**, 117505.
(DOI: <https://doi.org/10.1016/j.apenergy.2021.117505>)
- Cramton, P. (2017). Electricity market design. *Oxford Review of Economic Policy* **33**(2), 589-612.
- Davidson, R., and Mackinnon, J.G. (1993). *Estimation and inference in econometrics*. Oxford University Press.
- EIA (2022). U.S. liquefied natural gas exports to Europe increased during the first 4 months of 2022. <https://www.eia.gov/todayinenergy/detail.php?id=52659#> (Accessed on 06/21/2022).

- Haldrup, N., and Nielsen, M.O. (2006). A regime switching long memory model for electricity prices. *Journal of Econometrics* **135** (1–2), 349–376.
(DOI: <https://doi.org/10.1016/j.jeconom.2005.07.021>)
- Hargreaves, J., Hart, E.K., Jones, R., and Olson, A. (2015). REFLEX: An adapted production simulation methodology for flexible capacity planning. *IEEE Transactions on Power Systems* **30**(3), 1306-1315. (DOI: [10.1109/TPWRS.2014.2351235](https://doi.org/10.1109/TPWRS.2014.2351235))
- Hitaj, C. (2013). Wind power development in the United States. *Journal of Environmental Economics and Management* **65**, 394-410.
(DOI: <https://doi.org/10.1016/j.jeem.2012.10.003>)
- Janczura, J., and Weron, R. (2010). An empirical comparison of alternate regime-switching models for electricity spot prices. *Energy Economics* **32**, 1059–1073.
(DOI: <https://doi.org/10.1016/j.eneco.2010.05.008>)
- Joskow, P.L., and Tirole, J. (2007). Reliability and competitive electricity markets. *Rand Journal of Economics* **38**(1), 60-84. (DOI: <https://doi.org/10.1111/j.1756-2171.2007.tb00044.x>)
- Joskow, P.L. (2013). Editorial: symposium on capacity markets. *Economics of Energy & Environmental Policy* **2**(2), v-vi.
- Joskow, P.L. (2021). Facilitating transmission expansion to support efficient decarbonization of the electricity sector. *Economics of Energy & Environmental Policy* **10**(2), 57-91.
(DOI: [10.5547/2160-5890.10.2.pjos](https://doi.org/10.5547/2160-5890.10.2.pjos))
- Karakatsani, N.V., and Bunn, D.W. (2008). Intra-day and regime-switching dynamics in electricity price formation. *Energy Economics* **30**, 1776–1797.
(DOI: <https://doi.org/10.1016/j.eneco.2008.02.004>)

- Li, R., Woo, C.K., Zarnikau, J., and Tishler, A. (2022). How price responsive is industrial demand for natural gas in the United States? *Utilities Policy* **74**, 101318.
(DOI: <https://doi.org/10.1016/j.jup.2021.101318>)
- Mahone, A., Subin, Z., Orans, R., Miller, M., Regan, L., Calviou, M., Saenz, M., and Bacalao, N. (2018). On the path of decarbonization. *IEEE Power & Energy Magazine* **16**(4), 58-68. (DOI: [10.1109/MPE.2018.2822865](https://doi.org/10.1109/MPE.2018.2822865))
- Mills, A.D., and Wiser, R.H. (2015). Strategies to mitigate declines in the economic value of wind and solar at high penetration in California. *Applied Energy* **147**, 269-278.
(DOI: <https://doi.org/10.1016/j.apenergy.2015.03.014>)
- Mills, A.D., Levin, T., Wiser, R., Seel, J., and Botterud, A. (2020). Impacts of variable renewable energy on wholesale markets and generating assets in the United States: A review of expectations and evidence. *Renewable and Sustainable Energy Reviews* **120**, 109670. (DOI: <https://doi.org/10.1016/j.rser.2019.109670>)
- Morales, J., and Conejo, A. (2011). Simulating the impact of wind production on locational marginal prices. *IEEE Transactions on Power Systems* **26**(2), 820–828.
(DOI: [10.1109/TPWRS.2010.2052374](https://doi.org/10.1109/TPWRS.2010.2052374))
- Peña, J.I., Rodríguez, R., and Mayoral, S. (2022). Cannibalization, depredation, and market remuneration of power plants. *Energy Policy* **167**, 113086.
(DOI: <https://doi.org/10.1016/j.enpol.2022.113086>)
- PJM (2018). PJM cost of new entry. Available at <https://www.pjm.com/~media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx> (accessed on 27 January 2022).
- Prol, J.P., Steininger, K.W., and Zilberman, D. (2020). The cannibalization effect of wind and solar in the California wholesale electricity market. *Energy Economics* **85**, 104552.
(DOI: <https://doi.org/10.1016/j.eneco.2019.104552>)

- Quint, D., and Dahlke, S. (2019). The impact of wind generation on wholesale electricity market prices in the midcontinent independent system operator energy market: an empirical investigation. *Energy* **169**, 456 – 466.
(DOI: <https://doi.org/10.1016/j.energy.2018.12.028>)
- Sovacool, B.K. (2014). Cornucopia or curse? Reviewing the costs and benefits of shale gas hydraulic fracturing (fracking). *Renewable and Sustainable Energy Reviews* **37**, 249-264.
(DOI: <https://doi.org/10.1016/j.rser.2014.04.068>)
- Spees, K., Newell, S.A., and Pfeifenberger, J.P. (2013). Capacity markets – lessons learned from the first decade. *Economics of Energy & Environmental Policy* **2**(2), 1-26.
- Stern, L. (1998). Merchant power plants: competing for financing in a deregulated industry. *The Journal of Structured Finance* **4**(3), 47–55.
- Stoft, S., 2002. *Power system economics: designing markets for electricity*. Wiley-IEEE Press.
- Williams, J.H., DeBenedictis, A., Ghanadan, R., Mahone, A., Moore, J., Morrow, W.R., Price, S., and Torn, M.S. (2012). The technology path to deep greenhouse gas emissions cuts by 2050: the pivotal role of electricity. *Science* **6064**, 53–59.
(DOI: [10.1126/science.1208365](https://doi.org/10.1126/science.1208365))
- Williams, J.H., Haley, B., Kahrl, F., Moore, J., Jones, A.D., Torn, M.S., and McJeon, H. (2014). Pathways to deep decarbonization in the United States. The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations. Available at <https://biotech.law.lsu.edu/blog/US-Deep-Decarbonization-Report.pdf> (accessed on 06/23/2022).
- Wiser, R., Bolinger, M., Hoen, B., Millstein, D., Rand, J., Barbose, G., Darghouth, N., Gorman, W., Jeong, S., Mills, A., and Paulos, B. (2021). Land-based wind market report:

- 2021 edition. Lawrence Berkeley National Laboratory. Available at <https://escholarship.org/content/qt4sb6r5mz/qt4sb6r5mz.pdf> (accessed on 06/23/2022).
- Woo, C.K., Lloyd, D., and Tishler, A. (2003). Electricity market reform failures: UK, Norway, Alberta and California. *Energy Policy* **31**(11), 1103-1115.
(DOI: [https://doi.org/10.1016/S0301-4215\(02\)00211-2](https://doi.org/10.1016/S0301-4215(02)00211-2))
- Woo, C.K., Olson, A., and Horowitz, I. (2006a). Market efficiency, cross hedging and price forecasts: California's natural-gas markets. *Energy* **31**, 1290-1304.
(DOI: <https://doi.org/10.1016/j.energy.2005.05.00>)
- Woo, C.K., King, M. Tishler, A., and Chow, L.C.H. (2006b). Costs of electricity deregulation. *Energy* **31**(6-7), 747-768.
(DOI: <https://doi.org/10.1016/j.energy.2005.03.002>)
- Woo, C.K., Horowitz, I., Horii, B., Orans, R., and Zarnikau, J. (2012). Blowing in the wind: vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas. *The Energy Journal* **33**(1), 207-229. (DOI: 10.5547/ISSN0195-6574-EJ-Vol33-No1-8)
- Woo, C.K., Horowitz, I., Zarnikau, J., Moore, J., Schneiderman, B., Ho, T., and Leung, E. (2016). What moves the *ex post* variable profit of natural-gas-fired generation in California? *The Energy Journal* **37**(3), 29-57. (DOI: 10.5547/01956574.37.3.cwoo)
- Woo, C.K., and Zarnikau, J. (2019). A nice electricity market design. *The Electricity Journal* **32**, 106638. (DOI: <https://doi.org/10.1016/j.tej.2019.106638>)
- Woo, C.K., Milstein, I., Tishler, A., and Zarnikau, J. (2019). A wholesale electricity market design *sans* missing money and price manipulation. *Energy Policy* **134**, 110988.
(DOI: <https://doi.org/10.1016/j.enpol.2019.110988>)

Woo, C.K., Zarnikau, J., Tsai, C.H., Cao, K.H., Qi, H.S., and Li, R. (2023). Regional revenues of solar and wind generation in Texas. *Energy Policy* **178**, 113586.

(DOI: <https://doi.org/10.1016/j.enpol.2023.113586>)

Wooldridge, J.M. 2010. *Econometric analysis of cross section and panel data*. MIT Press.

Zarnikau, J., Woo, C.K., Zhu, S., and Tsai, C.H. (2019). Market price behavior of wholesale electricity products: Texas. *Energy Policy* **125**, 418-428.

(DOI: <https://doi.org/10.1016/j.enpol.2018.10.043>)

Zarnikau, J., Zhu, S., Woo, C.K., and Tsai, C.H. (2020a). Texas's operating reserve demand curve's generation investment incentive. *Energy Policy* **137**, 111143.

(DOI: <https://doi.org/10.1016/j.enpol.2019.111143>)

Zarnikau, J., Tsai, C.H., and Woo, C.K. (2020b). Determinants of the wholesale prices of energy and ancillary services in the U.S. Midcontinent electricity market. *Energy* **195**,

117051. (DOI: <https://doi.org/10.1016/j.energy.2020.117051>)

Table 1. Descriptive statistics of hourly data; sample period = 01/01/2014 - 10/31/2020; hourly per MWh procurement cost = min(hourly energy price, $HR \times$ daily natural gas price), where $HR = 7$ MMBtu per MWh for a CCGT-based tolling agreement

Panel A: Day-ahead hourly data for MISO's Northern region of LRZ 1 to 7

Variable	Number of non-missing observations	Mean	Standard deviation	Minimum	Maximum	Correlation	
						Energy price	Per MWh procurement cost
Energy price (\$/MWh)	419160	26.96	13.44	-20.02	463.94	1.000	0.624
Per MWh procurement cost (\$/MWh)	419328	19.28	5.82	-20.02	54.95	0.624	1.000
Energy price – per MWh procurement cost	419160	7.68	10.81	0.00	425.02	0.907	0.237
Natural gas price (\$/MMBtu)	419328	2.89	0.83	1.36	7.85	0.470	0.865
System AS requirement (MW)	419328	2442.00	137.76	2310.00	2997.00	0.095	0.060
Local wind generation (MWh)	418572	817.20	1339.00	0.00	11064.00	-0.260	-0.249
Total non-local wind generation (MWh)	418572	4903.00	3226.00	21.39	19806.00	-0.139	-0.140
Local nuclear generation (MWh)	419328	998.47	622.57	0.00	1980.00	-0.021	-0.004
Total non-local nuclear generation (MWh)	419328	10395.00	1325.00	5609.00	13460.00	0.007	-0.001
Local must-run generation (MWh)	419328	4292.00	2268.00	0.00	13199.00	0.366	0.285
Total non-local must-run generation (MWh)	419328	31370.00	7898.00	9508.00	57435.00	0.502	0.468
Local load (MWh)	419328	7751.00	2954.00	2452.00	20142.00	0.316	0.153
Total non-local load (MWh)	419328	65604.00	10892.00	40008.00	113227.00	0.501	0.248

Panel B: Real-time hourly data for MISO's Northern region of LRZ 1 to 7

Variable	Number of non-missing observations	Mean	Standard deviation	Minimum	Maximum	Correlation	
						Energy price	Per MWh procurement cost
Energy price (\$/MWh)	419328	26.33	20.23	-172.85	1862.00	1.000	0.447
Per MWh procurement cost (\$/MWh)	419328	18.78	6.39	-172.85	57.05	0.447	1.000
Energy price – per MWh procurement cost	419328	7.55	18.29	0.00	1830.00	0.950	0.146
Natural gas price (\$/MMBtu)	419328	2.89	0.85	1.33	8.15	0.284	0.744
System AS requirement (MW)	419307	2441.00	139.43	1135.00	2997.00	0.059	0.059
Local wind generation (MWh)	419328	814.46	1330.00	0.00	9861.00	-0.189	-0.270
Total non-local wind generation (MWh)	419328	4887.00	3183.00	0.00	17866.00	-0.122	-0.151
Local nuclear generation (MWh)	419328	994.44	620.82	0.00	1990.00	-0.008	0.002
Total non-local nuclear generation (MWh)	419328	10349.00	1353.00	0.00	13447.00	0.011	0.021
Local must-run generation (MWh)	419328	4112.00	2121.00	0.00	12576.00	0.241	0.302
Total non-local must-run generation (MWh)	419328	30253.00	7597.00	1948.00	55576.00	0.320	0.447
Local load (MWh)	419328	7831.00	2966.00	2504.00	19845.00	0.211	0.170
Total non-local load (MWh)	419328	66245.00	10690.00	41755.00	110784.00	0.325	0.248

Panel C: Day-ahead hourly data for MISO's Southern region of LRZ 8 to 10

Variable	Number of non-missing observations	Mean	Standard deviation	Minimum	Maximum	Correlation	
						Energy price	Per MWh procurement cost
Energy price (\$/MWh)	179640	28.14	12.37	4.78	1297.00	1.000	0.554
Per MWh procurement cost (\$/MWh)	179712	20.07	5.68	4.78	54.95	0.554	1.000
Energy price – per MWh procurement cost	179640	8.07	10.37	0.00	1272.00	0.890	0.113
Natural gas price (\$/MMBtu)	179712	2.89	0.83	1.36	7.85	0.526	0.990
System AS requirement (MW)	179712	2442.00	137.76	2310.00	2997.00	0.071	0.022
Local wind generation (MWh)	179712	0.00	0.00	0.00	0.00	-	-
Total non-local wind generation (MWh)	179388	5720.00	3472.00	67.00	19810.00	-0.117	-0.152
Local nuclear generation (MWh)	179712	1468.00	868.08	0.00	3442.00	-0.026	0.007
Total non-local nuclear generation (MWh)	179712	9926.00	1361.00	5622.00	13149.00	-0.050	-0.026
Local must-run generation (MWh)	179712	1873.00	1573.00	0.00	6865.00	0.160	0.176
Total non-local must-run generation (MWh)	179712	33789.00	8428.00	9736.00	61802.00	0.491	0.419
Local load (MWh)	179712	6366.00	5017.00	423.00	23862.00	0.166	0.024
Total non-local load (MWh)	179712	66988.00	11768.00	37403.00	116238.00	0.426	0.159

Panel D: Real-time hourly data for MISO's Southern region of LRZ 8 to 10

Variable	Number of non-missing observations	Mean	Standard deviation	Minimum	Maximum	Correlation	
						Energy price	Per MWh procurement cost
Energy price (\$/MWh)	179712	27.76	24.45	-198.57	1823.00	1.000	0.331
Per MWh procurement cost (\$/MWh)	179712	19.76	5.78	-198.57	57.05	0.331	1.000
Energy price – per MWh procurement cost	179712	8.00	23.18	0.00	1791.00	0.972	0.100
Natural gas price (\$/MMBtu)	179712	2.89	0.85	1.33	8.15	0.284	0.925
System AS requirement (MW)	179703	2441.00	139.43	1135.00	2997.00	0.040	0.034
Local wind generation (MWh)	179712	0.00	0.00	0.00	0.00	-	-
Total non-local wind generation (MWh)	179712	5701.00	3422.00	0.00	17870.00	-0.083	-0.164
Local nuclear generation (MWh)	179712	1461.00	874.38	0.00	3475.00	-0.007	0.005
Total non-local nuclear generation (MWh)	179712	9883.00	1384.00	0.00	13112.00	-0.031	-0.011
Local must-run generation (MWh)	179712	1859.00	1565.00	0.00	7291.00	0.093	0.171
Total non-local must-run generation (MWh)	179712	32506.00	8125.00	3226.00	59549.00	0.258	0.437
Local load (MWh)	179712	6419.00	5091.00	424.33	23840.00	0.095	0.033
Total non-local load (MWh)	179712	67657.00	11572.00	39759.00	114244.00	0.224	0.179

Notes: (1) The average levelized price of recently signed WPPA is ~\$25/MWh (Wiser et al., 2020, 2021), below the regional means of hourly energy prices by market type.

(2) Based on the cost of new entry (PJM, 2018), a CCGT's per MWh capacity is ~\$11.41/MWh, below the regional means of (hourly energy prices – hourly per MWh procurement costs) by market type.

Table 2. Regression results by region and market type; sample period = 01/01/2014 - 10/31/2020; per MWh procurement cost = $\min(\text{energy price}, HR \times \text{daily natural gas price})$, where $HR = 7$ MMBtu per MWh for a CCGT-based tolling agreement; statistically significant (p -value ≤ 0.01) coefficient estimates based on HAC standard errors (Wooldridge, 2010) in **bold**; anomalous coefficient estimates with unexpected signs in *italic*

Variable	Northern region				Southern region			
	DAM		RTM		DAM		RTM	
	Energy price (\$/MWh)	Per MWh procurement cost (\$/MWh)	Energy price (\$/MWh)	Per MWh procurement cost (\$/MWh)	Energy price (\$/MWh)	Per MWh procurement cost (\$/MWh)	Energy price (\$/MWh)	Per MWh procurement cost (\$/MWh)
Number of non-missing observations	418383	418383	418383	418383	179307	179307	179307	179307
Regressand mean	26.964	19.284	26.333	18.781	28.140	20.067	27.764	19.765
Adjusted R^2	0.615	0.826	0.261	0.649	0.593	0.984	0.172	0.865
RMSE	8.338	2.427	17.402	3.779	7.895	0.713	22.266	2.127
Daily natural gas price (\$/MMBtu)	6.595	5.917	4.894	5.445	7.501	6.722	7.570	6.375
System AS requirement (GW)	2.241	1.308	3.457	1.530	1.466	0.436	1.459	0.957
Local wind generation (GWh)	-2.370	-0.790	-2.730	-1.020	-	-	-	-
Total non-local wind generation (GWh)	-0.420	-0.040	-0.580	-0.090	-0.140	-0.007	-0.270	-0.030
Local nuclear generation (GWh)	-3.700	-0.280	-2.570	-0.270	-2.240	-0.030	-2.690	-0.090
Total non-local nuclear generation (GWh)	-0.760	-0.070	-0.600	-0.070	-0.730	-0.030	-0.980	-0.030
Local must-run generation (GWh)	-0.430	-0.040	-0.280	<i>0.031</i>	-1.020	<i>0.001</i>	-1.210	<i>0.021</i>
Total non-local must-run generation (GWh)	-0.380	<i>0.017</i>	-0.220	<i>0.022</i>	-0.150	<i>0.011</i>	-0.120	<i>0.028</i>
Local load (GWh)	2.208	0.067	3.031	0.129	2.089	0.019	2.094	0.074
Total non-local load (GWh)	0.809	0.055	0.579	0.063	0.562	0.012	0.567	0.017

- Notes: (1) For brevity, this table omits the voluminous coefficient estimates for the intercept and binary indicators for hour of the day, day of the week, month of the year, and LRZs. Most (~80%) of these estimates are highly significant with p -values ≤ 0.01 .
(2) The Dickey-Fuller and Phillips-Perron unit root tests decisively reject (p -value < 0.01) the null hypothesis that the regression residuals are non-stationary. Hence, the regression results reported in this table are not spurious (Davidson and MacKinnon, 1993).
(3) This table uses GW instead of MW to measure system AS requirement and GWh instead of MWh to measure energy-related variables to better represent their coefficient estimates that would otherwise be very small in size.

Table 3. Results for λ_M = extent of incremental wind energy development by the end of 2042 without causing missing money for wind and natural-gas-fired generation

Scenario		Northern region		Southern region	
Nuclear plant retirement	Reduction in must-run generation (%)	DAM	RTM	DAM	RTM
No	0	190%	215%	47%	46%
	25	213%	225%	60%	61%
	50	231%	235%	73%	76%
	75	249%	244%	87%	91%
	100	267%	254%	100%	106%
Yes	0	369%	321%	141%	149%
	25	387%	331%	154%	164%
	50	405%	341%	168%	174%
	75	423%	351%	181%	183%
	100	441%	360%	194%	192%

Note: The other assumptions used to construct this table are the \$1/MMBtu increase in natural gas price in the 2023-2042 period and the cumulative load growth of 20% by the end of 2042.

Table 4. Response analysis of λ_M (%) based on the OLS regression specification given by equation (3); number of observations = 40

Variable	Estimate	Standard error	<i>p</i> -value
Sample mean	212.50		
Adjusted R^2	0.97		
Root-mean-square error	20.61		
Intercept	222.98	7.98	< 0.001
$N = 1$ if nuclear plant retirement, 0 otherwise	118.04	6.52	< 0.001
$MG =$ reduction in must-run generation (%)	0.54	0.09	< 0.001
$R = 1$ if Southern region, 0 otherwise	-180.29	6.52	< 0.001
$D = 1$ if RTM, 0 otherwise	-13.11	6.52	0.052

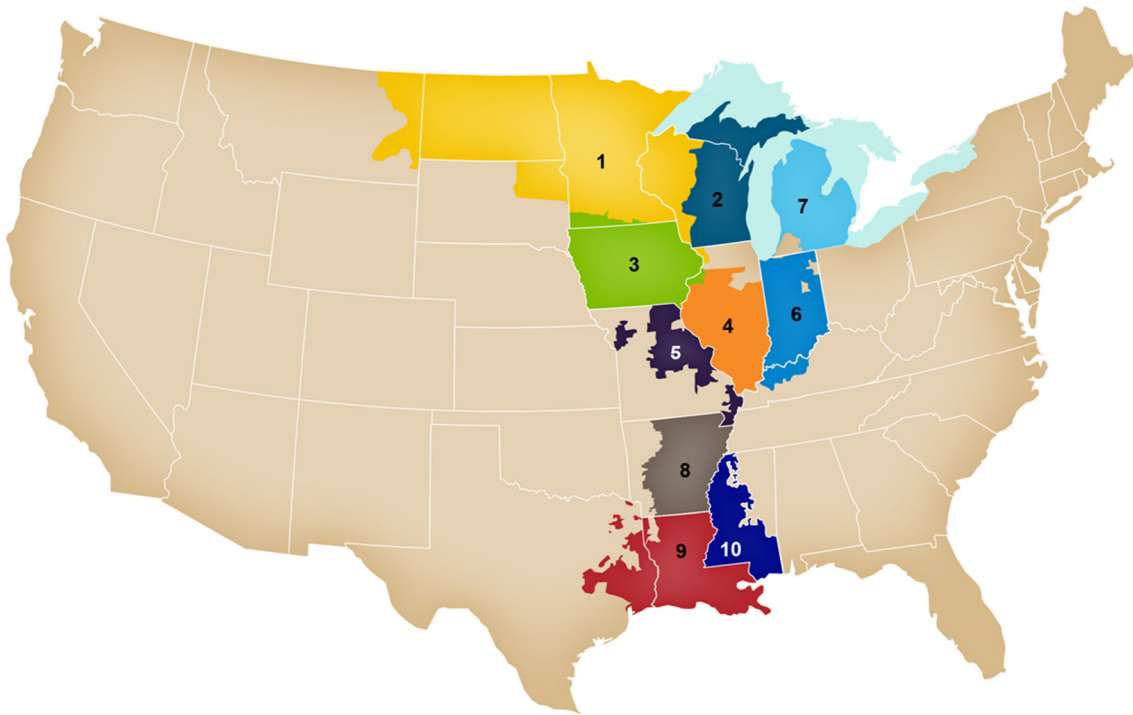


Figure 1. MISO's footprint and local resource zones (Source: MISO Tariff Attachment VV)