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Can the Basis Lead to Arbitrage Profits on the MISO Exchange?

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ABSTRACT

Previous research has shown the basis contains information about future spot prices in wholesale electricity markets. This paper examines the profitability of a trading rule that utilizes the basis on the Midcontinent Independent System Operator (MISO) exchange. 24 hourly time series regressions across each of MISO's eight regional hubs are estimated to determine the rule's effectiveness. 67 of the 192 total regressions yield statistically significant results. The number of significant results as well as the size of the returns tend to be highest during the afternoon through early evening hours, which calls into question the efficiency of the market during peak demand times.

Keywords: Electricity derivatives, Market efficiency, Midwest Independent System Operator
JEL Classifications: G10, G12, G20

1. INTRODUCTION

The deregulation of electricity markets in the United States led to the creation of several regional transmission operators (RTOs) across the country. RTOs are responsible for coordinating the flow of electricity within their respective geographical footprint. When it was established in 2013, the Midwest Independent System Operator (MISO) footprint covered several midwestern states and Manitoba. Since then, MISO has expanded to the southern United States and been rebranded as the Midcontinent Independent System Operator. MISO is geographically the largest RTO in the United States.

In addition to coordinating the flow of electricity, MISO also manages spot (real-time) and forward (day-ahead) markets for wholesale electricity across 8 regional hubs. Market clearing prices for day-ahead and real-time power on the exchange are referred to as Locational Marginal Prices (LMPs). LMPs are quoted in dollars per megawatt hour ($/MWh) and correspond to the marginal cost of supplying electricity to a given node in the footprint. Nodal day-ahead and real-time LMPs are calculated as

$$LMP_i = MEC_r + MLC_i + MCC_i \tag{1}$$

where MEC_r is the marginal energy cost at reference bus r, while MLC_i and MCC_i represent the marginal loss component and marginal congestion component at node , respectively (MISO 2022a). Please refer to MISO 2022a for a complete description of the LMP calculation process.

Real-time bids and offers must be submitted by 30 min prior to the hour in which the power is to be traded while day-ahead bid and offers must be submitted by 10:30 EST on the day prior to delivery. MISO then applies a Security Constrained Economic Dispatch algorithm to nodal real-time and day-ahead LMPs as described in Equation 1.

MISO aggregates nodal LMPs to hub-level, hourly LMPs. MISO then posts 24 hourly day-ahead and real-time LMPs for each of its 8 regional hubs. Real-time and day-ahead contracts may be settled either physically or financially (virtually). Combined, these markets cleared over $40 billion in 2021 (MISO 2022b).

While several authors have examined the information contained in the basis (the difference between the forward price in period t for delivery in t+1 and the spot price in time t) for several commodities, research on the basis is limited as it relates to wholesale electricity markets. Huisman and Kilic (2012) and Jones (2021) find a positive relationship between the basis and future spot price movements for wholesale electricity contracts. This is the first study to construct a trading rule to determine if the information contained in the basis can generate both statistically and economically significant returns. The trading rule produces statistically significant returns throughout the day across each regional hub, with economically significant results generally occurring during on-peak demand hours.

The rest of this paper is structured as follows. Section 2 provides a review of the literature and Section 3 describes the methodology. Results are presented in Section 4 and Section 5 concludes.

2. LITERATURE REVIEW

In his seminal paper, Fama (1970) defines a weak-form efficient market as one in which relevant historical information is fully incorporated in current prices. The weak-form inefficiency of wholesale power markets is well documented and has been attributed to the unique characteristics of electricity (virtually non-storable, negative prices, price spikes, etc.) as well as non-competitive behavior by market participants.

Virtual settlement allows those without the capacity to generate or receive wholesale power to participate in energy trading, which in theory, should mitigate arbitrage opportunities. However, Parsons et al. (2015) note that functional differences between day-ahead and real-time markets create inefficiencies which persist despite the existence of virtual bidding. Bessembinder and Lemmon (2002); Longstaff and Wang (2004); and Junttila et al. (2018), among many others, document significant forward premiums and discounts on a variety of power exchanges globally, which can lead to arbitrage returns.

Borenstein, et al. (2001) adopt a strategy that signals participants to buy (sell) in the day-ahead market and sell (buy) in the real-time market if the previous period's day-ahead price was below (above) the previous period's real-time price. Essentially, their rule examines arbitrage returns available to investors who use the realized forward premium to predict future forward premiums. Their strategy produced statistically and economically significant results in the months leading up to the failure of California's wholesale electricity market.

Inefficient pricing has also been tied to non-competitive behavior. Borenstein et al. (2002) find that generators in California withhold capacity during peak demand hours. Brown and Olmstead (2017) report similar results in Alberta and suggest that the exertion of market power is necessary to incentivize investment in power generation.

While the basis has been found to have forecasting power on future real-time prices, prior research has not explored if this forecasting power can be leveraged to generate arbitrage returns. This study extends the current literature by examining if the basis can lead to statistical and/or economically significant returns on the MISO exchange. Specifically, a straightforward trading rule is applied that creates buy/sell signals in the real-time market based on the relationship between currently available spot and forward prices.

3. METHODOLOGY

This research focuses on the arbitrage profits available to someone who uses historical relationships between the basis and changes in spot prices to place bids and offers in the real-time market. Fama and French (1987) define the basis as follows:

$$Basis_t = F_{t,t+1} - S_t \quad (2)$$

Where $F_{t,t+1}$ is the period t futures price for delivery in period t+1 and S_t is the period t spot price. The authors find that the basis contains information about future spot price changes for commodities with a high storage cost. While electricity is practically non-storable, Huisman and Kilic (2012) and Jones (2021) report that the basis has predictive power on spot prices in wholesale power markets.

As mentioned previously, MISO operates real-time and day-ahead markets for each regional hubs: Arkansas (AR), Illinois (IL), Indiana (IN), Louisiana (LA), Michigan (MI), Minnesota (MN), Mississippi (MS), and Texas (TX). This sample includes 24 hourly day-ahead and real-time prices for each of the eight hubs from January 01, 2018 to December 12, 2021. Each hourly time series consists of 1461 observations. MISO posts LMP data on their website, https://www.misoenergy.org/.

This study incorporates a straightforward test of basis's ability to produce arbitrage returns. The following two equations are employed for each hourly time series across each of the 8 MISO hubs:

$$Basis_{i,j,t} = DA_{i,j,t} - RT_{i,j,t} \quad (3)$$

$$RT_{i,j,t} - RT_{i,j,t-1} = \alpha + \beta_{(i,j)}(Rule) + \varepsilon_t \quad (4)$$

where $Basis_{i,j,t}$, $DA_{i,j,t}$, $RT_{i,j,t}$ are the basis, day-ahead LMP, and real-time LMP for hour i of hub j on day t, respectively. The trading rule is defined as follows:

$Rule = 1$ *if* $Basis_{i,j,t} > 1.1^* (RT_{i,j,t} - RT_{i,j,t-1})$

$Rule = -1$ *if* $Basis_{i,j,t} < 0.9^* (RT_{i,j,t} - RT_{i,j,t-1})$, otherwise,

$Rule = 0$

The beta coefficient represents the estimated profit (in terms of \$/MWh) earned by employing the rule for a particular hour on a given hub. Equation 4 is estimated via OLS with heteroscedasticity and autocorrelation-consistent (Newey-West) standard errors.

It is important to note that this approach differs from much of the literature that examines the basis or forward premia in power markets. Generally, authors combine individual hourly time series into larger categories (Borenstein et al. 2001) or evaluate a subset of the entire market (Longstaff and Wang, 2004). Evaluating each hourly time series independently allows for arbitrage return comparisons between hours and across hubs. The efficacy of the rule described in Equation 4 is evaluated for each hourly time series on every hub within the MISO footprint.

4. RESULTS

Average hourly real-time prices are shown in Table 1. The last column shows the average price per hour across all 8 MISO hubs. On average, real-time electricity is cheapest at 03:00 ($20.56) and most expensive for delivery at 13:00 ($37.63). Overall, real-time prices tend to trade above $30/MWh from 09:00 until 20:00 and below $30 for the rest of the day. The last row of the table shows that the 24-h average cost of electricity per hub is highest in Texas ($31.20) and lowest in Minnesota ($25.76). The 24-h average cost of power in the northern hubs (IL, IN, MI, MN) is $28.67 which is similar to the $29.23 average cost found in the southern hubs (AR, LA, MS, TX). Averaging the two previous numbers reveal the overall average price of real-time electricity during the sample period is $28.95.

Tables 2-9 show the beta coefficients and t-statistics from the implementation of Equation 4 across the MISO footprint. 67 of the 192 regressions (34.9%) have statistically significant beta coefficients. As a robustness check, Equation 4 was respecified without the 110% and 90% breakout range with similar results. 4 of the 8 hubs had statistically significant profits for at least 10 h of the day. Three of these hubs (AR, LA, and MS) are in the newer, southern portion of MISO's footprint. The average value of the statistically significant beta coefficients is $1.87, which is about 6.45% (1.87/28.95) of the average cost of electricity during the sample period. While statistically significant results occur throughout the day on MISO's hubs, profits are generally smallest in the early morning hours and largest between 13:00 and 19:00. Statistically significant arbitrage returns are obtained in 29 of the 56 (51.78%) hourly time series regressions from 13:00-19:00. The average of the statistically significant profits in that time interval is $3.02, which is 8.62% of the average cost of electricity during that time window.

Evaluating profits earned between 13:00 and 19:00 for each hub reveals even larger inefficiencies. Although statistically significant profits are found for only 4 h in the Texas hub, each one occurs between 13:00 and 19:00 and produces exceptionally large returns. Arbitrageurs earn $5.72 per megawatt hour traded at 14:00, which is 14% of the average cost of electricity in Texas at 14:00. In Mississippi, profits of $4.50/MWh are found at 14:00, which represents 13.18% of the hub's real-time cost of power at 14:00.

The Table 2 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Arkansas hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

The Table 3 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Illinois hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

The Table 4 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Indiana hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

Table 1: Average Real Time Prices ($/MWh)

Hour	AR	IL	IN	LA	MI	MN	MS	TX	MISO Avg.
0:00	21.37	21.99	23.54	22.10	23.54	19.97	23.01	21.56	22.14
1:00	20.41	21.06	22.62	21.19	22.77	19.03	20.52	22.43	21.26
2:00	19.94	20.23	22.02	20.69	22.05	18.10	20.15	21.77	20.62
3:00	19.88	20.04	22.12	20.61	22.12	17.90	20.11	21.68	20.56
4:00	20.58	20.87	23.29	21.16	23.28	18.73	20.68	22.42	21.38
5:00	21.94	23.50	26.62	22.81	25.90	20.90	22.38	24.19	23.53
6:00	25.20	26.67	30.34	26.84	29.00	23.95	25.86	27.67	26.94
7:00	29.47	29.73	33.07	31.77	31.74	27.33	30.38	32.64	30.77
8:00	27.66	29.77	31.58	28.60	31.04	27.81	27.85	30.05	29.30
9:00	28.16	31.33	32.61	29.72	32.49	28.68	28.72	30.62	30.29
10:00	29.21	32.11	33.31	31.63	33.79	28.87	29.51	31.71	31.27
11:00	28.89	31.48	32.82	30.96	33.44	27.90	29.40	33.06	31.00
12:00	29.46	31.43	33.35	31.77	33.01	27.85	30.06	35.43	31.54
13:00	34.34	33.27	38.50	47.80	36.09	29.24	43.99	37.82	37.63
14:00	31.18	31.24	33.54	35.71	33.40	27.01	34.14	40.04	33.28
15:00	32.74	32.65	35.63	38.81	35.34	27.80	35.69	41.49	35.02
16:00	33.41	33.96	36.85	38.60	37.01	29.61	35.94	41.23	35.83
17:00	32.05	34.67	37.16	34.41	37.24	31.61	33.22	38.12	34.81
18:00	32.78	35.06	37.31	35.06	36.35	33.74	33.17	37.91	35.17
19:00	31.82	33.21	34.96	34.36	34.19	31.73	31.91	36.85	33.63
20:00	30.74	30.19	31.78	33.87	31.08	28.89	31.24	35.14	31.62
21:00	28.61	27.14	28.45	30.72	28.18	26.08	28.71	32.71	28.82
22:00	24.27	24.78	26.15	24.98	26.04	23.98	24.36	28.39	25.37
23:00	22.38	22.83	24.24	23.11	24.22	21.54	22.47	23.89	23.09
24-h Avg. Per Hub	27.35	28.30	30.49	29.89	30.14	25.76	28.48	31.20	

Table 2: Basis trading rule profits-Arkansas hub

Hour	βRule	t(βRule)
0:00	0.33	0.58
1:00	0.19	0.42
2:00	1.03	2.97**
3:00	0.12	0.36
4:00	0.55	1.88*
5:00	0.14	0.23
6:00	1.21	1.51
7:00	0.58	0.93
8:00	0.11	0.20
9:00	0.77	1.31
10:00	−1.56	−1.00
11:00	−0.55	−0.59
12:00	−0.41	−0.36
13:00	0.70	1.05
14:00	−0.24	−0.32
15:00	0.10	0.12
16:00	1.18	1.52
17:00	0.81	0.87
18:00	0.15	0.13
19:00	2.02	1.93*
20:00	0.30	0.35
21:00	0.32	0.71
22:00	0.59	1.60
23:00	−0.52	−1.55

**Significant at 5% level. *Significant at 10% level

Table 3: Basis trading rule profits-Illinois hub

Hour	βRule	t(βRule)
0:00	0.61	2.21**
1:00	0.57	2.63**
2:00	0.60	2.36**
3:00	0.45	1.49
4:00	0.82	0.97
5:00	−0.01	−0.02
6:00	0.75	1.54
7:00	2.32	1.61
8:00	1.61	1.69*
9:00	2.04	2.21**
10:00	1.24	1.02
11:00	1.41	1.57
12:00	1.12	1.55
13:00	2.31	2.40**
14:00	2.51	3.07**
15:00	0.62	0.64
16:00	2.32	2.10**
17:00	1.62	2.22**
18:00	2.17	2.06**
19:00	3.97	2.27**
20:00	6.89	1.24
21:00	6.86	1.14
22:00	1.24	1.87*
23:00	0.61	4.52**

*Significant at 10% level. **Significant at 5% level

The Table 5 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Louisiana hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

The Table 6 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Michigan hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

Table 4: Basis trading rule profits-Indiana hub

Hour	βRule	t(βRule)
0:00	0.45	1.17
1:00	0.55	2.65**
2:00	0.88	3.69**
3:00	0.77	2.81**
4:00	0.92	2.61**
5:00	0.94	1.41
6:00	1.06	1.06
7:00	1.68	1.99**
8:00	0.47	0.63
9:00	1.23	1.19
10:00	0.29	0.34
11:00	−0.32	−0.45
12:00	0.29	0.30
13:00	2.59	1.97**
14:00	1.37	1.65*
15:00	1.21	1.25
16:00	0.84	0.97
17:00	1.12	1.30
18:00	1.61	1.55
19:00	1.69	1.80*
20:00	0.85	1.54
21:00	1.06	1.95*
22:00	0.07	0.23
23:00	0.46	3.24**

*Significant at 10% level. **Significant at 5% level

Table 5: Basis trading rule profits-Louisiana hub

Hour	βRule	t(βRule)
0:00	0.20	0.91
1:00	0.38	2.08**
2:00	0.50	1.68*
3:00	0.75	2.45**
4:00	0.37	2.32**
5:00	0	−0.01
6:00	1.09	1.14
7:00	−0.31	−0.17
8:00	−0.38	−0.52
9:00	2.08	2.52**
10:00	1.56	1.33
11:00	1.46	1.17
12:00	1.22	1.95*
13:00	4.31	2.26**
14:00	4.71	1.79*
15:00	3.21	1.67*
16:00	4.66	2.01**
17:00	2.18	2.27**
18:00	2.45	2.53**
19:00	3.64	2.25**
20:00	7.66	1.27
21:00	8.19	1.13
22:00	0.76	1.28
23:00	0.01	0.03

*Significant at 10% level. **Significant at 5% level

The Table 7 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Minnesota hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

Table 6: Basis trading rule profits-Michigan hub

Hour	βRule	t(βRule)
0:00	1.14	1.96**
1:00	0.57	1.97**
2:00	1.37	2.61**
3:00	0.33	1.07
4:00	0.75	1.83*
5:00	0.64	1.10
6:00	1.00	0.95
7:00	−0.11	−0.07
8:00	0.57	0.87
9:00	1.39	1.50
10:00	0.88	0.97
11:00	−1.17	−0.90
12:00	−0.10	−0.11
13:00	3.70	2.65**
14:00	1.13	1.18
15:00	0.90	0.87
16:00	0.68	0.58
17:00	1.56	1.51
18:00	1.81	1.35
19:00	1.34	1.25
20:00	1.33	2.20**
21:00	1.01	1.70*
22:00	−0.20	−0.36
23:00	0.21	0.58

*Significant at 10% level. **Significant at 5% level

Table 7: Basis trading rule profits-Minnesota hub

Hour	βRule	t(βRule)
0:00	0.72	2.33**
1:00	0.49	1.41
2:00	0.14	0.34
3:00	0.12	0.32
4:00	0.01	0.04
5:00	−0.46	−1.19
6:00	−0.09	−0.19
7:00	0.43	0.47
8:00	−0.29	−0.43
9:00	−0.21	−0.22
10:00	−1.78	−0.97
11:00	−0.78	−0.76
12:00	−0.85	−0.76
13:00	1.04	1.71*
14:00	0.46	0.78
15:00	0.49	0.81
16:00	0.04	0.05
17:00	−0.28	−0.35
18:00	1.35	1.16
19:00	0.31	0.24
20:00	−0.31	−0.43
21:00	0.50	1.10
22:00	1.02	1.87*
23:00	0.64	3.42**

*Significant at 10% level. **Significant at 5% level

The Table 8 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Mississippi hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

The Table 9 shows returns (in terms of dollars per megawatt hour) and estimated t-statistics from employing Equation 4 on the Texas hub. Each hourly time series is estimated via OLS with HAC (Newey-West) standard errors.

Table 8: Basis trading rule profits-Mississippi hub

Hour	βRule	t(βRule)
0:00	0.28	1.26
1:00	0.35	3.17**
2:00	0.55	4.22**
3:00	0.45	2.63**
4:00	0.19	0.91
5:00	0.22	0.75
6:00	1.18	1.55
7:00	−0.30	−0.17
8:00	0.71	1.52
9:00	2.12	2.64**
10:00	1.03	1.13
11:00	2.10	2.33**
12:00	0.65	1.19
13:00	4.14	2.18**
14:00	4.50	1.96**
15:00	2.65	2.34**
16:00	3.01	2.89**
17:00	1.83	2.48**
18:00	0.52	0.57
19:00	3.21	2.36**
20:00	1.59	1.42
21:00	7.19	1.10
22:00	0.98	1.72*
23:00	0.23	1.17

*Significant at 10% level. **Significant at 5% level

Table 9: Basis trading rule profits-Texas hub

Hour	βRule	t(βRule)
0:00	0.42	1.47
1:00	0.89	1.44
2:00	0.99	1.47
3:00	1.03	1.22
4:00	1.91	1.30
5:00	1.55	0.97
6:00	2.61	1.48
7:00	3.14	1.17
8:00	0.17	0.18
9:00	1.34	1.54
10:00	1.36	1.07
11:00	−2.39	−0.87
12:00	−6.38	−1.04
13:00	1.91	1.39
14:00	5.72	2.49**
15:00	2.29	1.49
16:00	4.45	2.76**
17:00	2.71	2.01**
18:00	1.95	1.43
19:00	2.94	1.65*
20:00	−5.97	−0.76
21:00	−1.55	−0.38
22:00	0.12	0.13
23:00	0.23	1.17

*Significant at 10% level. **Significant at 5% level

5. CONCLUSION

This paper examines the arbitrage returns possible from utilizing the basis to create a trading rule on one of the largest wholesale electricity markets in the world. Significant returns were found for just over one third of the hourly time series during the sample period. While the rule generally produced insignificant results, exceptionally large returns were found during peak demand hours, which is consistent with prior literature regarding the efficiency of wholesale electricity markets. Future research could create trading rules that utilize the basis and forward premium to generate arbitrage returns.

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