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# Assessing the efficiency of US electricity markets

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**Abstract**

The recent California's energy crisis has raised doubts about the benefits of energy deregulation. While it is true that the California electricity market is in turmoil, other electricity markets like the Pennsylvania–NewJersey–Maryland (PJM) are doing fine. This paper assesses the mark of efficiency reached by the electricity markets in California, New York, and PJM. It also compares the degree of efficiency across markets (forward vs. real time) and across time. No significant differences between the California and PJM electricity markets were discovered in the year of California's energy crisis (2000) using the cointegration tests. This research suggests that differences in price behavior between these two markets during 2000 did not arise from differences in efficiency. According to our analysis and measures of efficiency, PJM and California electricity markets are more efficient than the New York market. Also, as these markets become more mature over time, their efficiency level goes up. We also found evidence that a multi-settlement scheduling system leads to higher efficiency.
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## 1. Introduction

The recent deregulation of the power industry in several parts of the United States has produced different results across states. California's deregulation has been characterized by skyrocketing wholesale electricity prices and several utilities on the brink of bankruptcy. The New York electricity market has encountered up to 30% increase in the electricity bills. On the other hand, the Pennsylvania–NewJersey–Maryland (PJM) electricity market is enjoying low energy prices. In fact, the users of this market initially saved 3 billion dollars on electricity bills. The turmoil in some of the electricity markets is casting a shadow of doubt on deregulation plans of other states. A better understanding of the real causes of the differences in performance across electricity markets in the US is needed to help resolve some of the important issues.

Market inefficiency, market power, inelastic demand, and constrained supply are often quoted as the main cause of the problems experienced by some of the electricity markets (see Borenstein, 2001). The aim of this paper is to assess the mark of efficiency reached by the electricity markets in California, New York, and PJM and see if some of the differences in price dynamics in these markets could be explained by the difference in their level of market efficiency. To the best of our knowledge a comparative analysis of efficiency among California, New York, and PJM electricity markets is novel.

For this study, hourly prices of day-ahead and real-time markets for each of the three power markets were collected. The price data was taken from the Independent System Operators website of each market and from the University of California Energy Institute (UCEI).[2] Some of the hourly price series were available by load zone and not per market. In those cases an aggregation was done using load-weighted averages. Given the data availability, a selected group of years was analyzed for each market: California (1998–2000), PJM (1999–2001), and New York (2000–2001). The results indicate that efficiency has risen with the maturity of the markets.

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[2] The web sites from which the data was retrieved were: www.nyiso.com, www.pjm.com, www.caiso.com, www.ucei.berkeley.edu/ucei.

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Interestingly, this research did not find California to be more inefficient than PJM and New York power markets during the year of the California's energy crisis (2000). The New York electricity market was found to be the least efficient among the three.

## 2. Comparison of California, PJM and New York electricity markets

This study analyzes the price dynamics of the power markets in California, PJM, and New York and compares the level of efficiency reached by each one of these markets. A market is efficient when all the relevant and ascertainable information is fully and immediately reflected in market prices. In an efficient market all players are well-informed and adjust their market strategies continuously to take advantages of the arbitrage opportunities. An arbitrage opportunity exists if it is possible to design a strategy that can yield riskless economic profits (See Fama, 1970 for details). There is plenty of literature that describes the functioning of California, PJM, and New York electricity markets. (See Blumstein et al., 2002, Cameron and Cramton, 1999, Kench, 2000 and Quan and Michaels, 2001.) A review of that literature points out important differences in market structure across states which may explain differences in market efficiency. Some of these differences are discussed below.

### 2.1. Maturity of the market

In new markets, even the most experienced traders may lack sufficient information to know ex ante what are the profitable trading opportunities ex-post. This of course would lead to missed arbitrage opportunities. As the market matures, market participants "learn" more about how the market works which allows them to be better prepared to take advantage of the arbitrage opportunities.[3] Removal of these arbitrage opportunities leads to higher market efficiency. Hence differences in "maturity" between markets may be relevant in explaining differences across markets.

California was the first US state to restructure its electricity market which started at the beginning of 1998. PJM, which is the oldest centralized dispatched network in the world, started its restructuring at the beginning of 1999. New York's deregulated electricity market also started operation in 1998 although it was later than California.[4]

[3] As noted by Borenstein et al. (2001), learning takes two forms: either the existing players become more sophisticated, or more sophisticated participants enter over time.

[4] Information obtained from the energy information administration www.eia.doe.gov.

### 2.2. Market participants

Having enough traders in the day-ahead market is necessary to ensure the liquidity of the market and to establish a transparent day-ahead market. The more the market participants are, the more liquid is the market. In markets with few players, one large enough player could create price differences between the spot and the forward market, which would persist if there are not enough traders to take advantage of these arbitrage opportunities. Borenstein et al. (2001) present evidence that in the summer of 2000 in California, one player (PG&E) tried to exercise monopsony power. They argue that this could explain the large differences between the forward and spot price observed in that period.

The number of market participants differs across markets. From our extensive conversation with traders, we learned that PJM is the most liquid market in the East. Traders suggest that market participants are attracted to PJM because of its lower transaction costs and its reputation of delivering transparent and reliable information. Traders complained that NY power market lacks transparency in delivering of information. See Longstaff and Wang (2002) for more on market participants in PJM.[5] See Borenstein et al. (2001) for more on market participants in the California power market.

### 2.3. Multi-settlement vs single-settlement scheduling systems

In the scheduling process two alternatives are available: multi-settlement and single-settlement systems. A multi-settlement system implies that the prices and quantities established in market phases prior to dispatch are binding forward contracts. The spot-market (run by the ISO) is used to settle any difference between the scheduled transactions and the actual transactions. In a single-settlement system the forward phase is used just for scheduling purpose, all transactions are settled at the spot market price (See Cameron and Cramton, 1999, for additional details).

California runs a multi-settlement system with day-ahead and hour-ahead phases prior to dispatch. In California, the day-ahead transactions are binding and settled at the day-ahead price. Similarly, the hour-ahead transactions are settled at the hour-ahead prices. Until May 31, 2000 PJM ran a single-settlement system. On June 1, 2000 PJM switched to a multi-settlement system that is similar to the California's system. The NY electricity market has day-ahead and hour-ahead phases as well as a real-time one. Like in California these markets work in a multi-settlement system, where the transactions in

[5] The number of members in PJM grew from 165 to 194 between 1999 to 2000. In 2001, the number of participants was 200.

the forward market (day and hour-ahead) are traded at the forward price. The balance between the real-time transactions and the scheduled ones is traded at the real-time price.

The multi and single-settlement systems have potential advantages and disadvantages which may have an impact on market efficiency. A multi-settlement system may increase the opportunities for arbitrage by running a binding day-ahead market which is repeated on an hour-ahead basis. It also reduces risk by providing price certainty to the generators before the actual dispatch (See Cameron and Cramton, 1999). On the other hand, a single-settlement system may lead to productive efficiency gains by lowering the transactions costs that a sequence of forward markets may produce.

### 2.4. Competing forward markets

Kench (2000) argues that having competitive forward markets which can trade with one another may reduce the arbitrage opportunities existing in the electricity markets by increasing the competitive discipline in the forward markets. Thus, differences in the organization of the forward markets across states may explain differences in market efficiency.

In California, competing scheduling coordinators (SCs) run the forward markets. The Independent System Operator (ISO) runs the transmission, ancillary and real-time markets. Among the SCs, the Power Exchange (PX) used to handle most of the trading in the California forward markets.[6] The PX ran auctions to establish energy prices and schedules for both the day-ahead and hour-ahead market. On the other hand, the Automated Power Exchange which is also an SC, runs a continuous forward market. The others SCs in California work through bilateral contracts to tailor consumers' needs. The energy prices in the different SCs converge as trading among SCs is permitted.

In PJM the participants can implement the day-ahead phase either by submitting bids to a centralized dispatch managed by the ISO or by decentralized bilateral schedules. Unlike California, PJM has just one centralized day-ahead dispatch which is administrated by the ISO. In the ISO-run day-ahead market, generators' offers must specify the prices and the ranges of output over which these prices apply. In the bilateral scheduling, participants indicate the amount of energy injected and withdrawn from each location in each hour of the following day. The ISO uses the bids of the centralized day-ahead market to run an optimization program. This determines the minimum cost order of dispatch that meets the forecasted load that is not going to be supplied by the bilateral arrangements in the next day. The results from the optimization program tell all the market participants the likelihood of selling or buying power over the next day. See Cameron and Cramton (1999) for more information.

Like in PJM, there are no competing centralized forward markets in New York. The centralized day-ahead dispatch is managed by the ISO which receives the bids from the market participants and produces a load forecasts for all hours of the following day. ISO runs an optimization program with the load forecast and the bids to determine the mix of generation for the next day that minimizes the production costs over the day while observing the constraints on the transmission system. The optimization program also computes the day-ahead market price.

The ISO-run day-ahead markets of PJM and New York are subject to the competitive discipline of the bilateral markets.[7] However, an ISO can use its power as grid manager to favor its day-ahead market undermining the fairness of the market and therefore its efficiency.

### 2.5. Long-tem markets

As suggested by Borenstein et al. (2001) the existence of many forums for trading over time (long-term, day-ahead, hour-ahead) encourages generators to compete more aggressively in the spot market as they have sold significant portions of their output in the forward markets. More aggressive competition should lead to faster learning and more efficiency. Till recently, California utilities were not allowed to get into long term contracts and more than 90% of the power was purchased in the spot market. Instead in PJM, utilities could lock in prices through long term contracts. Therefore only 10–20% of the power was bought in the spot market. Due to the higher flexibility available in PJM to meet its long term energy needs, the prices were less volatile in PJM as compared to California.

### 2.6. Ancillary services (AS)

As a generator has to decide how to bid in each market, a shock in the AS market is going to be reflected in the forward and spot markets. As noted by Quan and Michaels (2001), the structure of the AS market greatly complicates a generator's choice in bidding in the electricity markets. More bidding choices for a generator decrease its ability to find potentially riskless strategies.

In PJM just operating reserves and regulation are traded.[8] PJM assigns duties in providing regulation to all generators. If a generator can not provide regulation, it must meet its obligation by writing bilateral contracts.

[6] The PX filed for bankruptcy at the beginning of 2001.

[7] As any player can choose between submitting bids to the ISO-run day ahead market and bilateral market.

[8] Regulation refers to the services provided by generators to maintain a 60 Hz operating level in the transmission network.

Till May 31 2000, PJM used a cost based market for procuring regulation but in June 2000, PJM started procuring regulation using market prices.

In California the AS markets allocate: regulation, spinning reserves, non-spinning reserves, and replacement reserves.[9] In California's electricity market, AS are allocated using day-ahead and hour-ahead markets. For the day-ahead AS market, a generator submits bids in which it specifies the total capacity that the ISO can use for any of the four services (regulation, spinning reserves, non-spinning reserves and replacement reserves) and the energy price (uniform for all services). Each hour the ISO examines the system and determines the amount of AS it requires. The ISO resolves each market in sequence starting with regulation first and ending with reserve replacement. If a generator was not selected in the first AS it can still participate in the next AS market. The AS hour-ahead market operates similar to the AS day-ahead market. Unlike PJM, in California the generators do not bid in each one of the AS markets independently.

In New York, each one of the six AS is traded independently in the market. Suppliers receive payments according to the quantities supplied and the market clearing prices in the day-ahead and supplemental markets.

### 2.7. Fuel mix[10]

The volatility of the fuel prices varies depending upon the fuel. Volatility in fuel price causes volatility in the electricity prices because fuels are a major component of generators' costs. Therefore, a diversified fuel source may prevent excess volatility in the electricity prices. The lower volatility may lead to fewer arbitrage opportunities and a more efficient and stable market. In California most of the energy is provided by gas-fired (51%) and hydro (26%) generators. In contrast, PJM fuel mix is more diverse. It includes gas, hydro, coal and nuclear. Like PJM, the fuel mix in New York is also more diverse than in California. NY electricity market uses gas (17.2%), hydroelectric (23%) and nuclear (27%).

## 3. Market efficiency

### 3.1. Related work

Our approach to studying market efficiency in power markets is similar to previous empirical literature that focused on the price dynamics of power markets around the world. In De Vany and Wall (1999a, 1999b), the authors analyze the price dynamics of 11 interconnected regional markets in the western US between 1994–1996 for evidence of market integration. Their results show that markets were efficient and stable in that region. Von de Fehr and Harbord (1998) compare the degree of competition between the electricity markets of England and Wales, Norway, and Australia. It concludes that the differences in the degree of competition level across international electricity markets can be explained by the differences in market design. Quan and Michaels (2001) discuss the complex decisions faced by the generators in deciding how much to trade in the different California electricity markets (e.g. day-ahead market, spot market, ancillary market, etc). It argues that rational behavior leads generators to continuously adjust their strategies to take advantage of the arbitrage opportunities across markets. Kench (2000) examines the evolution of the competitive electricity markets in California and PJM. It also proposes regulatory modifications that may make these two markets more competitive. Cameron and Cramton (1999) analyzes the advantages and disadvantages of binding and non-binding day-ahead markets. Borenstein et al. (2001) evaluate the level of market integration between the California day-ahead market and the real-time market. It concludes that the price convergence between these two markets increased as time passed.

This research contributes to previous empirical literature by evaluating the efficiency of the three major power markets in the US (California, PJM, and New York). It computes a measure of market efficiency for each market for each of the years analyzed. It also compares the efficiency across different time markets and across states.

### 3.2. The Model

Traditionally, market efficiency is evaluated by the "predictability" of changes in the price. In an efficient market, one should not be able to make abnormal economic profits using readily available information. The current price should reflect all the relevant and ascertainable information. However, if prices are predictable, agents could use readily available information to design strategies that yield abnormal profits. It is important to note that this conventional measure of efficiency requires that the commodity be storable. For a non-storable commodity like electricity, the price predictability alone does not provide intertemporal arbitrage opportunities. For example, if the spot price of electricity is predictable and known to be higher tomorrow, one couldn't really buy more today, store it and consume it tomorrow to take advantage of the information. Electricity today and tomorrow are really two different commodities.[11]

[9] The types of reserves differ by the amount of time the generator has before it must begin supplying power to the grid and whether or not the facility must be synchronized to the grid while waiting in reserve.

[10] Data is provided by the Energy Information Administration.

[11] The authors would like to thank Richard Green for pointing this out.

However, in an institutional setup where forward, real time and bilateral markets are organized as substitute markets and are allowed to compete against each other, one could take advantage of the predictable prices and design strategies to earn riskless profits.[12] For example, assume both the forward and real-time prices are predictable. Let $p_t^{t-j}$ denote the forward price of electricity in period $t-j$ for delivery at time $t$ and $p_t^t$ denote the real-time price at time $t$. If the real-time price is expected to be more than the forward price, $x$ units of electricity can be bought in the forward market in period $t-j$ for delivery at a future time $t$ and be sold at real time $t$ to make a riskless profit of $x(p_t^t - p_t^{t-j})$, assuming there are no transaction costs.

If consumers and generators are allowed to play across different markets as is done in a multi-settlement system, one could use the stationary properties of two series to make positive profits. This is possible since different markets can deliver electricity at the same time and any difference in price in the markets for the same commodity would imply trading inefficiency. In Borenstein et al. (2001) the authors show that institutional impediments and traders' incomplete understanding of the markets could create such trading inefficiencies.

This study performs three tests to measure the efficiency of the electricity markets. First it evaluates the "predictability" of a price series by testing its "stationarity". A series $y_t$ is said to follow a stationary process if its mean, variance and autocorrelation are independent of time, implying that one could calculate the future values of a series using its current values. Secondly, it looks for arbitrage opportunities by checking if the expected return in the forward and the real markets are the same using cointegration analysis. Two series are cointegrated if they have a common trend and change roughly at the same rate. If the day-ahead and the real-time markets are cointegrated, a shock in the former will also be reflected in the latter and the expected return in both markets will be the same. The forward and real-time prices should be cointegrated for the market to be efficient, otherwise the difference in expected returns would create arbitrage opportunities and cause inefficiency. Thirdly, using the methodology given in Borenstein et al. (2001), it analyzes the price convergence between the day ahead and the real-time markets to determine whether persistent price differences exist between the forward and real-time markets.

### 3.2.1. Unit root tests

To test the stationarity of a series, we check for the presence of a unit root in the price series using the Augmented Dickey–Fuller (ADF) test (Dickey and Fuller, 1979). The ADF test requires the estimation of the following regression equation:

$$\Delta P_t = \alpha + \beta_0 P_{t-1} + \sum_{t=1}^{L} \beta_l \Delta P_{t-l} + e_t, \tag{1}$$

where $\Delta P_t$ is the change in the electricity price at time $t$. $\alpha$, $\beta_0$ and $\beta_1$ are the coefficients, $P_{t-1}$ is the electricity price in period $t-1$ and $e_t$ is the residual.

The null hypothesis of this test is $\beta_0$=0. The number of lags in Table 1 were determined by initially estimating a general model with 15 lags and then in successive estimations the insignificant lags were dropped.[13] This procedure makes sure that the results of the ADF test are not misleading and the residuals in eq. (1) are uncorrelated.

As pointed out earlier, the stationarity in one market alone does not necessarily imply inefficiency in the electricity market. This is due to the non-storable nature of the electricity which allows for predictable intertemporal variation in prices. See Bessembinder and Lemmon (2002); Pirong and Jermakyan (1999) and Eydeland and Geman (1998) for more details. However, if both the day ahead and the real-time markets are stationary and a multi-settlement system is allowed, it could lead to arbitrage opportunities.

### 3.2.2. Cointegration analysis

As was mentioned in the earlier discussion of market efficiency, the expected return in the day-ahead and real-time markets for the same hour should grow at the same rate. Note that both markets trade the same commodity. If the expected return in one market is more than the other, there would be an opportunity to make riskless profit and the market would be inefficient. In time series analysis, if two series track one another and grow roughly at the same rate, they are said to be cointegrated. By definition, cointegration necessitates that the two series be integrated of the same order and have a common trend. The order of integration is the number of times a non-stationary series has to be differentiated to obtain a stationary series. Two series with different order of integration cannot be cointegrated. An important consequence of cointegration is that it is possible to find a linear combination of the cointegrated series that generates a stationary series. This property is used in testing for cointegration. The following cointegration relation was tested here:

$$P_{d,h} = \alpha + \beta P_{r,h} + \varepsilon_h, \tag{2}$$

where $P_{d,h}$ is the price of the day-ahead market at hour $h$, and $P_{r,h}$ is the price of the realtime market at hour $h$.

[12] See Quan and Michaels (2001) for an excellent discussion on opportunities available to generators to play across markets.

[13] From the correlograms of the series, 15 lags appeared to be sufficient to take into account the serial correlation in the data for the Augmented Dickey–Fuller tests. This approach follows the methodology of De Vaney and Wall (1999b).

Table 1
Results of Augmented Dickey–Fuller unit root test for California electricity market. An asterisk (*) indicates that the ADF statistic rejects the null hypothesis of unit root at 99% confidence level; ** shows the hours when both the day ahead and real-time markets reject the null hypothesis

| California | | | | | | |
|---|---|---|---|---|---|---|
| Hours | 1998 | | 1999 | | 2000 | |
| | Real | Day ahead | Real | Day ahead | Real | Day ahead |
| 1 | −4.33* | −0.75 | −2.64 | −2.84 | −2.57 | −0.96 |
| 2 | −2.53 | −2.74 | −2.24 | −2.98 | −1.74 | −1.10 |
| 3 | −1.53 | −2.64 | −2.32 | −2.88 | −1.70 | −1.65 |
| 4 | −2.11 | −1.88 | −3.23 | −2.94 | −1.62 | −1.65 |
| 5 | −2.55 | −2.05 | −3.11 | −2.55 | −1.54 | −1.61 |
| 6 | −2.12 | −2.44 | −2.64 | −2.44 | −1.65 | −1.32 |
| 7 | −3.27 | −2.26 | −2.29 | −2.68 | −1.36 | −0.99 |
| 8 | −2.11 | −3.02 | −2.57 | −3.19 | −1.37 | −1.69 |
| 9 | −1.86 | −2.91 | −2.57 | −3.89* | −1.31 | −1.53 |
| 10 | −1.73 | −2.95 | −2.71 | −6.5 | −1.46 | −1.90 |
| 11 | −1.83 | −2.87 | −2.66 | −2.81 | −2.34 | −1.80 |
| 12 | −3.33 | −2.96 | −2.72 | −2.69 | −2.77 | −2.44 |
| 13 | −2.46 | −3.24 | −3.10 | −2.71 | −2.82 | −2.31 |
| 14 | −2.14 | −3.07 | −3.99* | −2.87 | −3.74* | −2.70 |
| 15 | −1.74 | −2.80 | −3.76* | −3.10 | −3.46* | −2.69 |
| 16 | −1.95 | −2.65 | −3.65* | −3.14 | −2.98 | −2.70 |
| 17 | −1.59 | −2.74 | −4.06* | −3.16 | −3.29 | −2.63 |
| 18 | −1.75 | −3.64* | −5.07** | −3.71** | −2.52 | −2.56 |
| 19 | −1.68 | −3.75* | −2.79 | −6.95* | −2.35 | −2.52 |
| 20 | −2.17 | −4.19* | −2.94 | −6.33* | −1.87 | −2.44 |
| 21 | −2.01 | −3.74* | −3.78** | −6.55** | −2.22 | −2.30 |
| 22 | −1.93 | −2.31 | −2.67 | −2.87 | −2.11 | −2.03 |
| 23 | −1.60 | −2.40 | −3.02 | −3.33 | −0.67 | −0.69 |
| 24 | −2.06 | −1.41 | −2.61 | −3.21 | −0.67 | −0.60 |
| Stationary hours in both day ahead and real time | 0 | | 2 | | 0 | |

$\alpha,\beta$ are the parameters of the cointegration vector and $\epsilon_h$ is the error.

This paper uses the Johansen test to determine the cointegration between the day-ahead and real-time market for each hour. The application of the Johansen test requires the estimation of a Vector Autoregressive model (VAR) of the form:

$$P_t = \Gamma_0 + \Gamma_1 P_{t-1} + \Gamma_2 P_{t-2} + \ldots + \Gamma_k P_{t-k} + e_{t-k}, \qquad (3)$$

where $P_t$ is the column vector with the day-ahead and real-time prices. $\Gamma_i$ is the matrix of parameters and $\epsilon$ is the disturbance.

The number of lags in the estimated VAR model were determined using the Schwarz information criteria (See Grasa, 1989). Under cointegration the matrices of parameters in eq. (3) should be short ranked. The Johansen test uses this property to test for cointegration. See Johansen (1991) for details.

Based on the results of the unit roots and cointegration tests, a measure of efficiency for each year and state market was constructed in the following way:

$$E_{i,j} = \frac{Ch_{i,j}}{24} \times 100, \qquad (4)$$

where $E_{i,j}$ is the efficiency of market $i$ in year $j$ and $Ch_{i,j}$ is the number of cointegrated hours of market $i$ in year $j$.

### 3.2.3. Price convergence

Similar to the analysis performed in Borenstein et al. (2001) to determine trading inefficiencies between the forward and the spot market, we analyze the price convergence between the day ahead and the real-time market and provide another measure of market efficiency.[14] We extend the work done in Borenstein et al. (2001) by measuring price convergence in PJM, NY, and California markets (Borenstein et al. (2001) analyzed price convergence just in California). In addition, we measure price convergence hour by hour. Persistent price differences between the day ahead market and the real-time market would imply the presence of arbitrage opport-

[14] The authors would like to thank an anonymous referee for his suggestion to perform this test.

Table 2
Results of Augmented Dickey–Fuller unit root test for PJM electricity market. In 1999, PJM day ahead market had no price data since PJM used a single settlement system and all settlements cleared at real-time market prices. An asterisk (∗) indicates that the ADF statistic rejects the null hypothesis of unit root at 99% confidence level; ∗∗ shows the hours when both the day ahead and real-time markets reject the null hypothesis

| Pennsylvania−New Jersey−Maryland | | | | | | |
|---|---|---|---|---|---|---|
| Hours | 1999 | | 2000 | | 2001 | |
| | Real | Day ahead | Real | Day ahead | Real | Day ahead |
| 1 | −2.78 | NA | −1.88 | 0.74 | −2.07 | −3.78∗ |
| 2 | −2.79 | NA | −0.48 | 1.23 | −3.35 | −3.74∗ |
| 3 | −3.26 | NA | −0.14 | 0.32 | −3.18 | −3.44 |
| 4 | −3.41 | NA | −0.90 | 0.26 | −1.91 | −3.26 |
| 5 | 3.45 | NA | 0.05 | 0.64 | −2.39 | −3.34 |
| 6 | −3.78∗ | NA | −1.20 | 0.23 | −5.14∗ | −1.88 |
| 7 | −3.92∗ | NA | −1.55 | 0.91 | −2.00 | −1.17 |
| 8 | −4.47∗ | NA | −0.93 | 0.33 | −1.73 | −1.14 |
| 9 | −3.85∗ | NA | −1.78 | −0.20 | −2.37 | −1.42 |
| 10 | −3.39 | NA | −2.50 | −0.54 | −2.22 | −1.55 |
| 11 | −10.59∗ | NA | −3.28 | −1.90 | −2.38 | −1.90 |
| 12 | −10.40∗ | NA | −7.99∗∗ | −4.76∗∗ | −7.68∗ | −1.41 |
| 13 | −10.95∗ | NA | −4.00∗∗ | −4.82∗∗ | −2.09 | 0.62 |
| 14 | −3.34 | NA | −7.75∗∗ | −3.61∗∗ | −1.49 | −0.51 |
| 15 | −3.57∗ | NA | −2.56 | −3.20 | −0.15 | 0.02 |
| 16 | −5.40∗ | NA | −2.78 | −2.66 | −0.34 | 0.01 |
| 17 | −7.40∗ | NA | −3.20 | −3.91∗ | −0.12 | −0.42 |
| 18 | −5.05∗ | NA | −1.25 | −0.18 | −2.55 | −1.68 |
| 19 | −10.27∗ | NA | −0.18 | 0.39 | −2.96 | −3.10 |
| 20 | −9.29∗ | NA | −1.57 | 0.02 | −1.94 | −1.85 |
| 21 | −14.94∗ | NA | −3.43 | −1.21 | −3.25 | −2.25 |
| 22 | −14.51∗ | NA | −2.16 | −1.65 | −8.81 | −2.47 |
| 23 | −3.78∗ | NA | −1.37 | −1.10 | −2.91 | −2.22 |
| 24 | −5.01∗ | NA | −0.33 | 1.52 | −9.22∗ | −2.96 |
| Stationary hours in both day ahead and real time | 0 | | 3 | | 0 | |

unities. In an efficient market with risk neutral traders and no transaction costs, day ahead and the real-time price of the electricity for delivery at the same time and location should be the same. In other words, the day ahead price at time $t-j$ for delivery at time $t$ must incorporate all the information available at time $t-j$ about the expected real-time price at time $t$, i.e.

$$P_t^{t-j} = \exp(P_t^t|\Phi_{t-j}),$$

where $P_t^{t-j}$ is the day ahead price at time $t-j$ for delivery at time $t$, $P_t^t$ is the real-time price at time $t$ and $\Phi_{t-j}$ is the information available at time $t-j$. The above equation can be rewritten as:

$$P_t^t = P_t^{t-j} + \varepsilon_t.$$

Here $\epsilon_t$ is the white noise. According to this equation, the day ahead price is an unbiased predictor of the real-time price and incorporates all the available information at time $t-j$. We test the market efficiency by testing if the day ahead price converges to the real-time price through the following model:

$$P_t^t - P_t^{t-j} = \theta + \varepsilon_t.$$

If the day ahead price is an unbiased predictor of the real-time price, $\theta$ would be zero.

Following the methodology outlined in Borenstein et al. (2001), for each state and each year, we estimate hourly OLS regressions based on the Newey–West procedure (see Newey and West, 1987). The results are shown in Tables 5, 6 and 7. A measure of efficiency similar to the one given in Table 4 is constructed in the following way:

$$\varepsilon_{i,j} = \frac{H_{i,j}}{24} \times 100, \qquad (5)$$

where $\epsilon_{ij}$ is the efficiency of market $i$ in year $j$ and $H_{ij}$ is the number of hours when the day ahead price is an unbiased predictor of the real-time price for market $i$ in year $j$.

Table 3
Results of Augmented Dickey–Fuller unit root test for PJM electricity market. An asterisk (∗) indicates that the ADF statistic rejects the null hypothesis of unit root at 99% confidence level; ∗∗ shows the hours when both the day ahead and real-time markets reject the null hypothesis

| New York | | | | |
|---|---|---|---|---|
| Hours | 2000 | | 2001 | |
| | Real | Day ahead | Real | Day ahead |
| 1 | −11.36∗ | −2.82 | −3.34 | −3.46 |
| 2 | −11.91∗ | −2.21 | −3.04 | −3.44 |
| 3 | −2.43 | −2.60 | −3.00 | −3.46 |
| 4 | −12.32∗ | −2.21 | −3.76∗ | −3.46 |
| 5 | −3.06 | −2.25 | −3.24 | −2.64 |
| 6 | −3.37 | −1.64 | −1.96 | −2.77 |
| 7 | −2.23 | −1.56 | −2.14 | −1.93 |
| 8 | −2.83 | −2.74 | −1.99 | −1.80 |
| 9 | −2.30 | −2.02 | −3.12 | −2.17 |
| 10 | −3.45 | −3.32 | −9.81∗ | −2.40 |
| 11 | −4.20∗ | −3.24 | −3.07 | −2.75 |
| 12 | −2.57 | −3.01 | −9.84∗∗ | −3.56∗∗ |
| 13 | −3.03 | −3.06 | −9.60∗ | −3.18 |
| 14 | −5.18∗∗ | −4.31∗∗ | −3.17 | −3.11 |
| 15 | −3.29 | −3.36 | −3.58∗ | −2.98 |
| 16 | −5.38∗ | −2.82 | −3.55∗ | −2.62 |
| 17 | −11.70∗ | −2.55 | −3.41 | −3.05 |
| 18 | −3.21 | −2.64 | −8.72∗ | −3.41 |
| 19 | −11.95∗ | −2.49 | −3.74∗ | −3.02 |
| 20 | −3.05 | −2.21 | −3.72∗ | −2.97 |
| 21 | −11.91∗ | −1.90 | −2.98 | −3.26 |
| 22 | −4.10∗ | −1.86 | −5.76∗∗ | −3.51∗∗ |
| 23 | −11.29∗ | −2.23 | −4.17∗ | −3.46 |
| 24 | −7.53∗ | −1.53 | −2.65 | −3.54∗ |
| Stationary hours in both day ahead and real time | 1 | | 2 | |

## 4. Results and discussion

Tables 1, 2 and 3 show the unit root test results for each hour in a year, in California, PJM, and New York, respectively. From the tables it can be observed that in all the three states, some hours were stationary. For efficiency, the hours of interest are the ones when both the day ahead and the real-time price series are stationary. The higher the number of such hours, the more inefficient is the market. In California the number of hours when both the day ahead and real-time price series were stationary increased from 0–2 between 1998 and 1999; and then dropped to 0 in 2000. The increase in inefficiency between 1998 and 1999 could have been due to the significantly higher wholesale prices and artificially set price caps. These price caps had not been triggered in 1998.

For PJM, the real-time market had a high number of stationary hours in 1999 when PJM had the single settlement system. The number of stationary real-time market hours dropped significantly in 2000 and 2001. This could be due to the fact that PJM switched to a multisettlement system in 2000 from a single-settlement system. As noted in Section 2 of this paper, a multi-settlement system runs binding forward markets which offers market players more forums to trade and therefore more opportunities for learning and arbitrage. See Cameron and Cramton (1999) for more on the functioning of multi- and single-settlement systems.

The number of hours when both the day ahead and real-time prices were stationary dropped from 3 to 0 between 2000 and 2001 implying that the PJM market became more efficient over time. As explained in Section 2, as a market matures, the players in the market become more sophisticated and therefore more capable of taking advantage of arbitrage opportunities. On the other hand, PJM’s reputation for cost efficiency and reliability has attracted more participants over time which may have increased its efficiency. The higher the number of participants, more liquid and efficient is the market.

In NY, based on our first measure of market efficiency, there was no significant change in the market efficiency between 2000 and 2001. The number of hours

Table 4
Johansen Cointegration Tests. An asterisk (∗) indicates that the cointegration hypothesis is rejected at 95% confidence level. An × indicates that either the day ahead or the real-time price series is stationary and ×× shows when both the day ahead and the real-time series are stationary

| Hours | California | | | PJM | | New York | |
|---|---|---|---|---|---|---|---|
| | 1998 | 1999 | 2000 | 2000 | 2001 | 2000 | 2001 |
| 1 | × | 60.83 | 83.51 | 18.85∗ | × | × | 67.77 |
| 2 | 10.66∗ | 60.07 | 31.96 | 29.13 | × | × | 49.64 |
| 3 | 8.77∗ | 90.38 | 25.19 | 48.95 | 106.11 | 128.16 | 84.86 |
| 4 | 45.10 | 165.37 | 47.36 | 69.34 | 112.25 | × | × |
| 5 | 19.8 | 30.58 | 36.96 | 41.61 | 103.93 | 102.88 | 86.68 |
| 6 | 42.02 | 35.65 | 20.98 | 35.56 | × | 112.98 | 86.05 |
| 7 | 12.40∗ | 26.30 | 14.16∗ | 30.00 | 23.20 | 38.95 | 51.63 |
| 8 | 82.28 | 29.26 | 18.14∗ | 32.93 | 15.74∗ | 67.06 | 52.44 |
| 9 | 48.28 | × | 55.55 | 41.60 | 26.97 | 63.25 | 30.36 |
| 10 | 44.04 | × | 64.03 | 127.59 | 73.86 | 199.94 | × |
| 11 | 53.13 | 39.18 | 119.73 | 125.66 | 98.32 | × | 139.59 |
| 12 | 67.98 | 57.71 | 142.41 | ×× | × | 227.27 | ×× |
| 13 | 25.4 | 98.12 | 135.73 | ×× | 86.93 | 214.87 | × |
| 14 | 29.97 | × | × | ×× | 84.08 | ×× | 138.29 |
| 15 | 27.43 | × | × | 138.86 | 28.62 | 211.41 | × |
| 16 | 23.76 | × | 225.05 | 131.92 | 97.55 | × | × |
| 17 | 27.54 | × | 46.85 | × | 81.48 | × | 124.47 |
| 18 | × | ×× | 126.36 | 110.84 | 9.23 | 210.98 | × |
| 19 | × | × | 156.44 | 103.28 | 92.66 | × | × |
| 20 | × | × | 29.16 | 85.15 | 83.81 | 201.80 | × |
| 21 | × | × | 123.58 | 110.89 | 113.89 | × | 101.73 |
| 22 | 39.06 | 109.27 | 82.75 | 109.36 | × | × | ×× |
| 23 | 36.84 | 105.97 | 127.73 | 96.09 | 102.26 | × | × |
| 24 | 9.75∗ | 95.48 | 51.32 | 28.85 | × | × | × |
| Integrated hours | 15 | 14 | 20 | 19 | 17 | 12 | 12 |
| Efficiency (%) | 63 | 59 | 83 | 79 | 71 | 50 | 50 |

when both the day ahead and real-time prices were stationary increased from 1 to 2 between 2000 and 2001. This could be due to the low liquidity that still characterizes the NY market. As noted in Section 2 low liquidity could explain low efficiency.

Table 4 shows the efficiency results as measured by the cointegration tests. In California, the forward and real-time markets were cointegrated 63% of the hours in 1998 which increased to 83% in 2000. This improvement may be explained by a "learning by doing" process as players learn from their past experience and exploit all the arbitrage opportunities available in the market, ultimately making the market more efficient. In PJM, efficiency in 2000 and 2001 was high (>70$). However, there was no significant change in the number of cointegrated hours between these two years. Comparing California and PJM in year 2000, it is noteworthy that California was slightly more efficient than PJM. In fact California had the highest level of efficiency among the three markets. In New York the market efficiency measure stayed at 50% in 2000 and 2001. The low level of efficiency in New York between 2000 and 2001 may be explained by the existence of barriers and transaction costs that stopped traders from taking advantage of the arbitrage opportunities, high levels of risk aversion among players (see Borenstein et al., 2001) and low liquidity that characterizes NY with respect to PJM or California.

Tables 5, 6 and 7 show the results of market efficiency as measured by the price convergence between the day ahead and the real-time market for California, PJM and New York, respectively. Table 5 shows that California was extremely inefficient in 1998 where every single hour the day ahead price was significantly different from the real-time price. The situation changed dramatically in the following years. In 1999, only in 3 out of 24 hours the day ahead price did not converge to the real-time price and in 2000, this happened in 11 out of 24 hours. It is important to note that the California energy crisis was at its peak in the summer of 2000 and the prices were extremely volatile in that period. Taking this into consideration, we performed another analysis of year 2000 by excluding the high volatility summer months (May through August). Our results show that the number of hours when the day ahead price did not converge to the real-time price decreased from 11 to 3 in year 2000.

Table 6 shows that in PJM, the number of hours when the day ahead price did not converge to the real-time

Table 5
Price convergence test results for California. An asterisk (∗) indicates that the day ahead price and the real-time price are significantly different at 95% confidence. The lack of convergence of the day ahead price to the real-time price shows the degree of market inefficiency. $\theta$ is zero if the day ahead price is an unbiased predictor of the real-time price. S.E. shows the Newey–West standard errors and *P*-value shows the Newey–West *P*-value

| California | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Hours | 1998 | | | 1999 | | | 2000 | | |
| | $\theta$ | S.E. | *P*-value | $\theta$ | S.E. | *P*-value | $\theta$ | S.E. | *P*-value |
| 1 | −9.14 | 1.40 | 0∗ | −0.63 | 0.40 | 0.11 | 13.53 | 3.48 | 0.000l∗ |
| 2 | −9.77 | 1.28 | 0∗ | 0.30 | 0.41 | 0.45 | 10.32 | 3.14 | 0.00l∗ |
| 3 | −9.11 | 1.19 | 0∗ | 0.46 | 0.40 | 0.25 | 8.89 | 2.84 | 0.002∗ |
| 4 | −8.65 | 1.26 | 0∗ | −0.87 | 0.45 | 0.05∗ | 4.64 | 2.82 | 0.10 |
| 5 | −9.71 | 1.25 | 0∗ | −1.60 | 0.48 | 0.00l∗ | 7.21 | 2.73 | 0.008∗ |
| 6 | −12.31 | 1.51 | 0∗ | −1.35 | 0.35 | 0.0002∗ | 7.16 | 3.14 | 0.02∗ |
| 7 | −12.85 | 1.76 | 0∗ | −0.58 | 0.51 | 0.25 | 15.12 | 5.26 | 0.004∗ |
| 8 | −13.00 | 2.09 | 0∗ | 0.89 | 1.06 | 0.40 | 11.99 | 4.54 | 0.01∗ |
| 9 | −13.06 | 2.20 | 0∗ | −0.45 | 0.87 | 0.60 | 4.11 | 4.40 | 0.35 |
| 10 | −14.13 | 2.21 | 0∗ | −1.08 | 0.97 | 0.26 | 5.12 | 4.41 | 0.24 |
| 11 | −14.66 | 2.35 | 0∗ | 0.35 | 0.94 | 0.71 | 5.00 | 3.38 | 0.14 |
| 12 | −12.66 | 2.78 | 0∗ | 0.16 | 0.63 | 0.79 | 4.04 | 4.01 | 0.31 |
| 13 | −15.82 | 2.66 | 0∗ | −0.62 | 0.60 | 0.29 | −3.09 | 4.62 | 0.50 |
| 14 | −15.67 | 3.00 | 0∗ | 1.07 | 0.84 | 0.20 | 6.71 | 4.84 | 0.16 |
| 15 | −15.09 | 3.28 | 0∗ | 1.04 | 0.94 | 0.26 | 11.07 | 5.41 | 0.04∗ |
| 16 | −14.40 | 3.77 | .0002∗ | 1.11 | 1.13 | 0.32 | 8.55 | 5.93 | 0.15 |
| 17 | −15.64 | 3.71 | 0∗ | −0.20 | 0.97 | 0.83 | 6.46 | 6.38 | 0.31 |
| 18 | −17.58 | 3.87 | 0∗ | 0.69 | 1.11 | 0.53 | −0.85 | 6.10 | 0.88 |
| 19 | −18.19 | 3.15 | 0∗ | 1.86 | 1.31 | 0.15 | −3.37 | 6.11 | 0.58 |
| 20 | −16.15 | 2.81 | 0∗ | 1.21 | 1.14 | 0.28 | −8.14 | 6.45 | 0.20 |
| 21 | −15.92 | 2.61 | 0∗ | 0.18 | 0.95 | 0.84 | 8.98 | 5.23 | 0.08 |
| 22 | −12.61 | 2.42 | 0∗ | 0.62 | 0.52 | 0.23 | 20.19 | 6.08 | 0.00l∗ |
| 23 | −10.87 | 2.25 | 0∗ | 0.34 | 0.60 | 0.56 | 9.82 | 3.03 | 0.00l∗ |
| 24 | −11.34 | 1.71 | 0∗ | −0.25 | 0.39 | 0.51 | 12.35 | 3.16 | 0.00l∗ |
| Efficiency (%) | | 0 | | | 87 | | | 54[a] | |

[a] The efficiency increases to 87% after excluding the volatile summer months of year 2000.

price, went up from 5 in year 2000 to 8 in year 2001. However, in New York, as shown in Table 7, this number went down from 8 in year 2000 to 6 in year 2001.

In 2000 the electricity prices in California and New York skyrocketed, whereas in PJM they remained stable. Interestingly, for our first two measures of efficiency, in 2000 there was no significant difference between California and PJM, suggesting that the differences in price behavior between these two markets were not due to market efficiency.[15] For the third measure of efficiency, PJM appears to be more efficient than California, however if the high volatile summer months of 2000 are excluded, the efficiency in these two markets are similar.[16] Thus, other potential explanations (e.g. market power, supply constraints) should be explored to understand the differences in price dynamics between California and PJM power markets in 2000.

On the other hand, the New York market was significantly more inefficient than PJM in 2000 for all the three measures of efficiency. For 2001, PJM was significantly more efficient than NY with the first two measures of efficiency but for the third measure, NY had 8% higher efficiency than PJM. The higher efficiency of PJM with respect to NY in the period of analysis could be explained by higher liquidity, low transaction costs and more transparent availability of information in PJM as compared to NY.

An efficiency ranking of the three state electricity market renders California as the most efficient and New York as the least efficient for year 2000. The characteristics that contributed to making California the most efficient in 2000 might have been its high level of maturity, multi-settlement system and competing for-

[15] For the second measure of efficiency, California is 4% more efficient than PJM in 2000.

[16] For the third measure of efficiency, without summer months, California is 8% more efficient than PJM in 2000.

Table 6
Price convergence test results for PJM. An asterisk (*) indicates that the day ahead price and the real-time price are significantly different at 95% confidence. The lack of convergence of the day ahead price to the real-time price shows the degree of market inefficiency. $\theta$ is zero if the day ahead price is an unbiased predictor of the real-time price. S.E. shows the Newey–West standard errors and $P$-value shows the Newey–West $P$-value

| Pennsylvania−New Jersey−Maryland | | | | | | |
|---|---|---|---|---|---|---|
| Hours | 2000 | | | 2001 | | |
| | $\theta$ | S.E. | $P$-value | $\theta$ | S.E. | $P$-value |
| 1 | −1.08 | 0.43 | 0.01* | 0.39 | 0.68 | 0.56 |
| 2 | 0.21 | 0.31 | 0.50 | 1.86 | 0.67 | 0.006* |
| 3 | 0.55 | 0.29 | 0.05* | 0.98 | 0.51 | 0.06 |
| 4 | 0.48 | 0.33 | 0.14 | 0.40 | 0.52 | 0.44 |
| 5 | 0.53 | 0.34 | 0.12 | −0.25 | 0.51 | 0.62 |
| 6 | 0.19 | 0.62 | 0.76 | −1.04 | 0.76 | 0.17 |
| 7 | −1.43 | 1.66 | 0.39 | −4.16 | 1.27 | 0.001* |
| 8 | −1.48 | 1.51 | 0.97 | −1.79 | 1.59 | 0.26 |
| 9 | −3.37 | 1.71 | 0.05* | −5.35 | 1.30 | 0.0001* |
| 10 | −1.37 | 1.41 | 0.33 | −3.63 | 1.09 | 0.001* |
| 11 | 0.48 | 1.31 | 0.71 | −1.33 | 1.23 | 0.28 |
| 12 | −1.97 | 1.15 | 0.09 | 0.39 | 1.68 | 0.81 |
| 13 | −1.80 | 1.36 | 0.18 | −1.45 | 1.32 | 0.27 |
| 14 | 0.72 | 1.59 | 0.65 | 2.15 | 1.63 | 0.19 |
| 15 | −2.50 | 1.42 | 0.08 | −0.46 | 1.06 | 0.65 |
| 16 | −3.05 | 2.84 | 0.28 | −1.44 | 1.01 | 0.15 |
| 17 | −2.11 | 1.92 | 0.27 | −1.60 | 1.62 | 0.32 |
| 18 | −2.25 | 2.16 | 0.30 | −5.29 | 1.83 | 0.004* |
| 19 | −5.35 | 3.73 | 0.15 | −7.89 | 2.31 | 0.001* |
| 20 | −6.97 | 2.21 | 0.001* | −9.33 | 1.72 | 0* |
| 21 | −4.35 | 1.75 | 0.01* | −2.88 | 1.43 | 0.051 |
| 22 | −0.41 | 1.32 | 0.75 | −0.14 | 1.41 | 0.91 |
| 23 | −0.85 | 1.01 | 0.40 | −1.80 | 1.07 | 0.09 |
| 24 | −1.62 | 1.05 | 0.12 | −2.38 | 0.90 | 0.01* |
| Efficiency (%) | 79 | | | 67 | | |

ward markets. PJM was less efficient than California in 2000 due to lack of maturity as compared to California and its newly implemented multi-settlement system. The low efficiency in New York with respect to other markets may be explained by its lower liquidity and higher transaction costs.

## 5. Conclusions

This paper evaluates the efficiency of the power markets in California, PJM, and New York for the past few years. Several conclusions can be derived from our results. First, in both California and PJM, the efficiency of the power markets has improved with the maturity of the markets. Secondly, a multi-settlement scheduling system seems to be associated with higher market efficiency. Thirdly, contrary to common belief, in 2000 the California market appears to be as efficient as the PJM market based on our measure. Thus, the differences in price dynamics between these two markets cannot be explained by the differences in efficiency. However, an efficiency argument may be made to explain differences in prices between NY and PJM in that year.

## 6. Further research

Further research on the following topics could be explored: First, a cointegration analysis between the ancillary services markets, the forward, and the spot markets could be implemented using the same methodology discussed here. Secondly, similar analysis can be done in the deregulated electricity markets of other countries to see if similar conclusions hold there. Finally, other potential explanations that clarify the difference in price behavior of different markets could be explored more rigorously.

Table 7
Price convergence test results for New York. An asterisk (∗) indicates that the day ahead price and the real-time price are significantly different at 95% confidence. The lack of convergence of the day ahead price to the real-time price shows the degree of market inefficiency. $\theta$ is zero if the day ahead price is an unbiased predictor of the real-time price. S.E. shows the Newey–West standard errors and *P*-value shows the Newey–West *P*-value

| New York | | | | | | |
|---|---|---|---|---|---|---|
| Hours | 2000 | | | 2001 | | |
| | $\theta$ | S.E. | *P*-value | $\theta$ | S.E. | *P*-value |
| 1 | −4.75 | 1.69 | .005∗ | −5.47 | 1.37 | 0.0001∗ |
| 2 | −6.13 | 2.80 | 0.03∗ | −3.20 | 1.72 | 0.06 |
| 3 | −4.89 | 1.45 | 0.001∗ | −2.19 | 1.37 | 0.11 |
| 4 | −3.87 | 1.77 | 0.03∗ | −2.59 | 1.40 | 0.06 |
| 5 | −4.33 | 2.00 | 0.03∗ | −1.47 | 0.97 | 0.13 |
| 6 | −2.05 | 2.11 | 0.33 | −0.89 | 1.27 | 0.48 |
| 7 | −0.20 | 1.08 | 0.84 | 0.05 | 1.18 | 0.96 |
| 8 | −3.69 | 1.39 | 0.01∗ | −3.33 | 1.02 | 0.001∗ |
| 9 | 0.64 | 1.58 | 0.68 | 1.00 | 2.11 | 0.63 |
| 10 | −0.51 | 1.77 | 0.77 | 5.43 | 3.94 | 0.16 |
| 11 | −1.32 | 1.67 | 0.42 | 1.49 | 2.57 | 0.56 |
| 12 | −2.15 | 1.39 | 0.12 | 1.58 | 2.86 | 0.58 |
| 13 | −2.12 | 1.81 | 0.24 | −0.86 | 2.45 | 0.72 |
| 14 | −0.60 | 3.22 | 0.85 | 1.18 | 2.82 | 0.67 |
| 15 | 0.51 | 3.27 | 0.87 | −0.85 | 2.37 | 0.71 |
| 16 | 1.44 | 4.78 | 0.76 | −1.63 | 2.39 | 0.49 |
| 17 | 2.73 | 4.56 | 0.55 | −0.93 | 3.00 | 0.75 |
| 18 | 3.14 | 3.63 | 0.38 | 0.32 | 3.11 | 0.91 |
| 19 | 2.97 | 3.75 | 0.43 | −2.56 | 2.96 | 0.38 |
| 20 | 0.21 | 2.45 | 0.93 | −3.18 | 2.61 | 0.22 |
| 21 | 1.96 | 2.30 | 0.39 | −3.73 | 1.29 | 0.004∗ |
| 22 | −2.55 | 1.56 | 0.10 | −5.75 | 0.95 | 0∗ |
| 23 | −6.35 | 1.29 | 0∗ | −7.55 | 0.83 | 0∗ |
| 24 | −6.85 | 1.86 | 0.0003∗ | −4.44 | 1.21 | 0.0003∗ |
| Efficiency (%) | 67 | | | 75 | | |

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