International Experiences of Nodal Pricing Implementation

Frequently Asked Questions

Karsten Neuhoff
Climate Policy Initiative / DIW Berlin

Rodney Boyd
Climate Policy Initiative

Working document – this Version July 2011

Introduction

Policymakers and industry frequently discuss the merits of nodal pricing as a power market design to accommodate large scale renewables. This has raised questions about the practical steps involved in its implementation. This working document aims to collect "frequently asked questions" and gather international experience to provide some answers.[1]

Costs of transition

1. What are the one-time costs and annual benefits of a transition to nodal pricing?

Implications for energy trading

2. How are locational price differences hedged?
3. What structure can be used to allocate transmission rights?
4. How is liquidity of the transmission system ensured?
5. Does nodal pricing undermine the liquidity of forward markets?
6. Do retail customers face nodal prices?
7. How can we optimize the day-ahead and intraday markets to take advantage of improving wind forecasts?
8. Can nodal pricing regimes accommodate energy from hydro?

Technical details

9. How long does it take to calculate a market result for large systems?
10. What level of information exchange is necessary for secure system operation?
11. Can ISOs or TSOs better ensure system security?
12. Does it suffice to integrate day-ahead markets?

Institutional details

13. Who owns the ISO?
14. Is it possible to gradually extend an ISO?

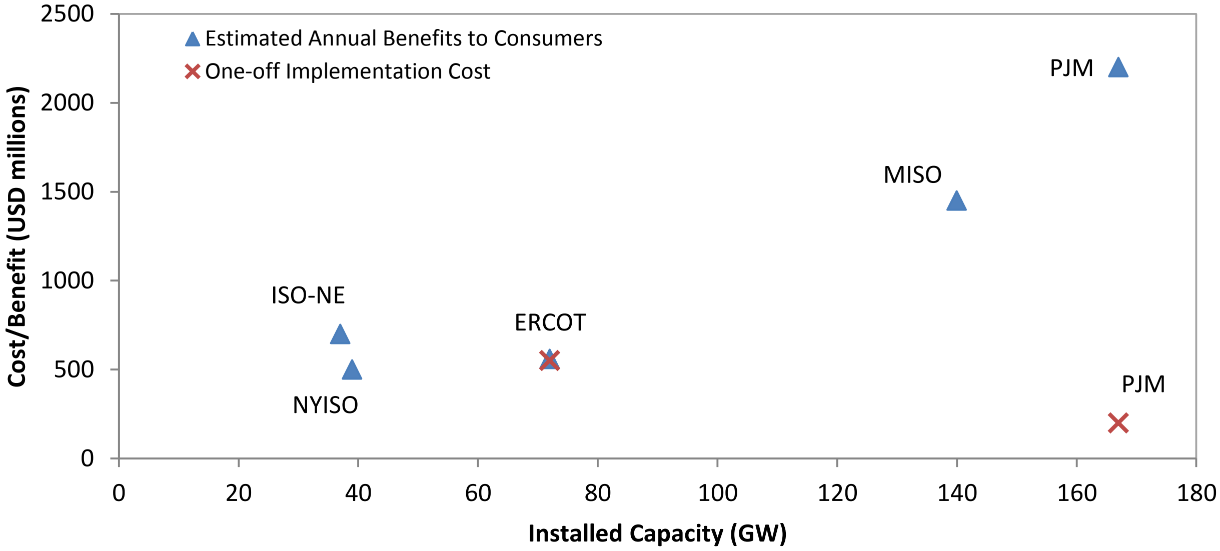
[1] We are grateful for detailed input and comments by Andy Ott, Christoph Weber, Bill Hogan and Mark Ellis

Costs of transition

1. What are the one-time costs and annual benefits of a transition to nodal pricing?

The implementation costs and annual benefits to consumers through efficiency savings for US Independent System Operators (ISOs) are depicted here from various sources:

Figure 1: Annual benefits and one-off implementation costs vs. installed capacity.



The figure illustrates that US ISOs that have undertaken - or are undergoing - transition to a nodal pricing regime have typically recovered the implementation costs (one-time costs) within one year of operation.

The ISO can typically take advantage of existing institutions' skills and experiences to operate the grid, and as a result, implementation costs are limited. The largest components of these costs are the additional need for specialized information technology (IT) software and hardware and personnel costs such as training.

On the other hand, benefits from moving to an integrated structure include (Eto et al., 2005)[2] better congestion management, improved grid reliability, increased retail access and competition, reduced transaction costs, improved planning, and better coordination with regulatory agencies.

As the accompanying studies on intraday markets and congestion management show, a variety of power market design aspects can impact the efficiency of the operation. The following studies have tried to assess the value of improving power market design.

[2] Eto, J. H., Lesieutre, B. C. & Hale, D. R., 2005. "A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies", December 2005.

Table 1: Various Cost-Benefit Studies of US ISOs.

US ISO	Study/Source	Modelled?	Observed?	Aspects covered in study
ERCOT	CRA International/ Resero Consulting for Texas PUC, 2008	Yes	-	Congestion management improvements, reduced costs of ancillary services, reduced gaming, improved competition.
MISO	MISO, 2009: *Start up and first year of operation*, MISO Value Proposition 2010	-	Yes	Improved system reliability, competition and management of assets. Reduced ancillary services. Annual benefits of $1.3-$1.6 bn include deferred investment. Actual benefit shown in graph.
ISO-New England	RTO, 2005: *Value of Independent ISOs*	-	Yes	Reduced wholesale market power price, improved dispatch.
NYISO	Analysis Group, 2007: *A CBA of NYISO Initial Years*	Yes	-	Benefits to O&M, improved market performance, improved generator dispatch
PJM	Andrew Ott, 2010: *Personal communication*, PJM Value Proposition 2010.	-	Yes	Reliability, congestion improvements. Generation investment savings, grid services savings (reduced ancillary and regulatory costs). Energy cost savings.

Implications for Energy Trading

2. How are locational price differences hedged?

The ability to hedge transmission price risk is an important element of a power market operating under a nodal pricing regime. As market participants may be exposed to locational pricing differences, operators of the market issue Financial Transmission Rights (FTRs): rights which entitle the holder to a stream of revenues (or charges) for differences between energy prices at source and delivery nodes.

FTRs do not offer the holder the right to physically transport electricity. Instead, FTRs offer the holder access to financial compensation equal to the congestion and/or loss rent associated with the locational price differences, hence they are also referred to as Congestion Revenue Rights (CRRs) in some US markets.

FTRs are a central component of all nodal pricing systems, but the number of years for which they are valid, whether they are defined as obligations or also available as options, the shares of FTRs that are allocated for free, and the principles that are used for such free allowance allocation, differ across regions.

3. What structure can be used to allocate transmission rights?

Allowing participants the opportunity to hedge against locational price differences is an important aspect of a nodal pricing system, and the initial allocation of FTRs is critical in order to minimise excess rent attributions:

> "The initial allocation of Congestion Revenue Rights is important to ensure that the implementation of Standard Market Design preserves the service rights of existing customers, provides access to all available capacity and minimizes cost shifts."[3]

[3] Page 208 from FERC, 2002 – Notice of Proposed Rulemaking (NOPR) Electricity Market Design and Structure, Docket Number: RM01-12-000.

One method of initial allocation is based on the physical rights of existing transmission customers (generators, large industry users, suppliers). They receive firm financial transmission rights or obligations based on their historical use of the system. The second allocation method is to make all FTRs available through an auction, and then assign winning participants with rights to the revenues generated – called Auction Revenue Rights discussed below in relation to ensuring liquidity.

Both approaches share the primary purpose of re-distributing congestion rents (benefits or losses). While the direct method of assignation protects existing actors from exposure to potential price changes before and after nodal implementation, in some circumstances this may increase potential barriers to entry since "holders of CRRs on congested paths may be reluctant to offer these in the secondary market [and] limit the ability of new suppliers to enter the market."[4]

The volume of rights that can be issued typically corresponds to the available transmission capacity. The revenue from congestion rents, thus allows the TSO to cover the financial commitments associated with FTRs (the *Revenue Adequacy Requirement*).

4. How is liquidity of the transmission system ensured?

As mentioned above, in addition to FTRs, most US nodal pricing regimes have introduced Auction Revenue Rights (ARRs) in an effort to encourage liquidity and financial arbitrage opportunities across the transmission system. ARRs have been introduced in addition to FTRs to encourage participation in the FTR auctions and increase liquidity.

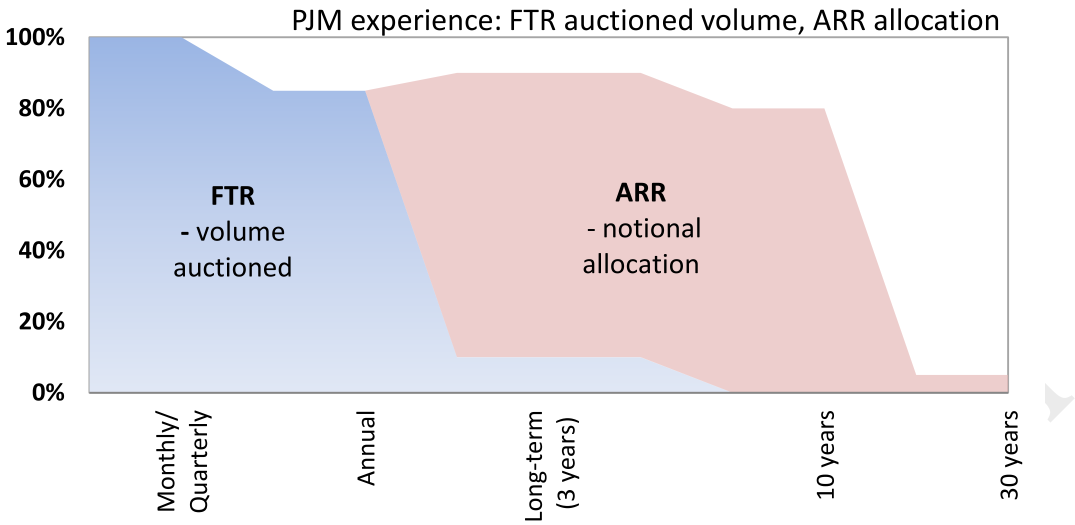
While FTRs are typically issued for periods ranging from one month to three years, ARRs are typically issued for 10-year periods. ARRs thus allow for long-term hedging of congestion costs in the transition to nodal pricing, but can stretch up to 30 years in the case of transmission expansion.

By participating in the FTR auctions, ARR owners can achieve the same hedging opportunities as with FTRs alone. Both ARRs and FTRs are financial entitlements, not physical rights. Both types of contracts are assessed here in parallel. In 2009 the combined value of transmission contracts was $2.4 billion (Ott, 2010).

Providing access to FTRs on various timelines is an important aspect of liquidity – with PJM offering the most alternatives (see below).

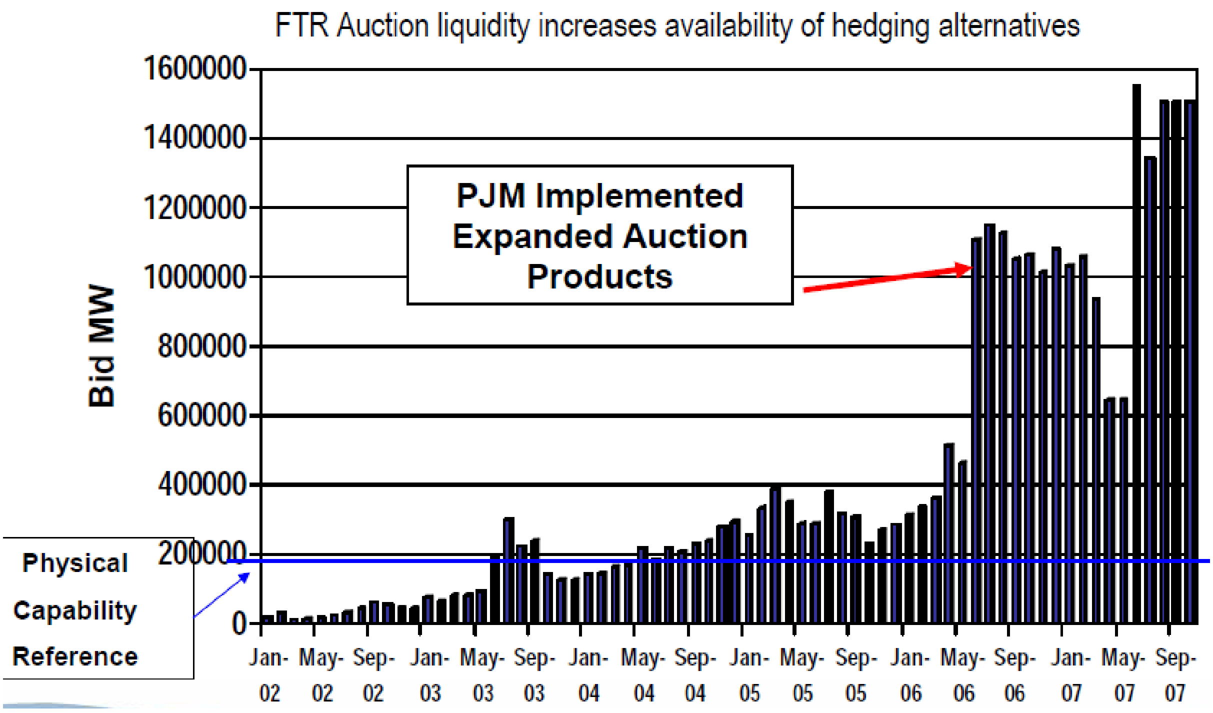
[4] Page 212 from FERC, 2002 –NOPR SMD, Docket Number: RM01-12-000.

Figure 2: Allocation of FTR and ARR (notional value) over various durations in PJM.



The next figure illustrates the liquidity of the FTR market. The trading volume of seven times physical available transmission capacity is an indicator of the maturity of the market. The implication of expanding the volume of the FTR market is that PJM was able to offer deep FTR market liquidity to load-serving entities, which provided enough hedging options to meet obligations. Reports indicate that as much as 150-200% of physical transfer capability is made available for hedging at competitive prices (within 10% of actual expected cost) (Ott, 2010).

Figure 3: FTR Auction liquidity in PJM (PJM, 2008).



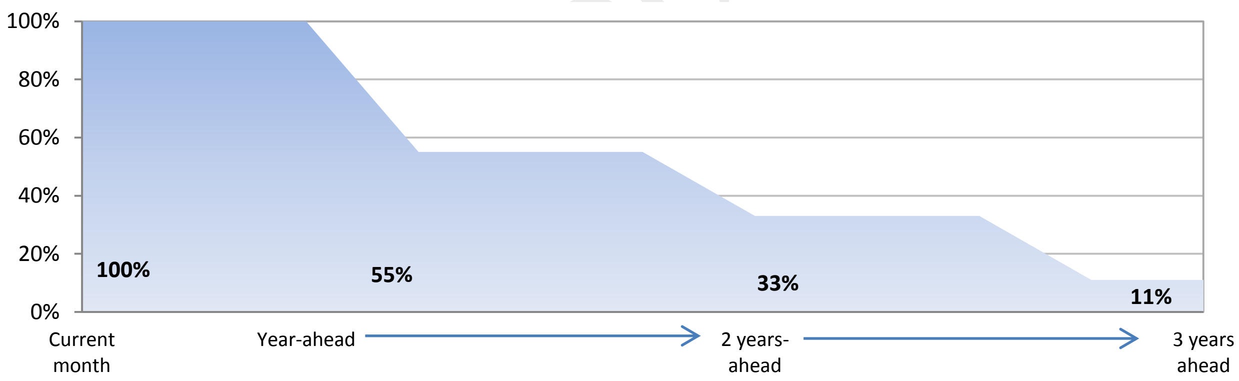
5. Does nodal pricing undermine the liquidity of forward markets?

In Europe, there is some concern that the multiplicity of nodes under nodal pricing regimes creates a level of complexity that inhibits the attempts of market participants to find counterparties for longer-term energy contracts.

In the US, trading hubs emerged that are based on a relatively stable average price across a set of nodes. Trading at and between these hubs is very liquid in the forward exchanges (e.g., the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE)). In PJM's case, standardized power contracts for both day-ahead and real-time market delivery are defined for 20 trading hubs, and NYMEX provides a monthly contract for PJM's Western Hub (800MWh total), likely to be the most liquid forward electricity market in the world.

The next figure illustrates the level of forward contracting observed among PJM market participants at the PJM Western Hub: 55% of the total PJM energy to serve load for the year is contracted on one year ahead interest, 33% for two years ahead, and 11% for three years. When we consider all actively traded hubs across all exchanges within the PJM network, liquidity in one year ahead power transactions exceed peak energy requirement by a factor of 4 to 5; the three year forward is twice the annual requirement. Where price differences between a local trading hub and the reference node of a generation or demand asset are significant, generators can use FTRs to hedge the locational price difference.

Figure 4: Typical forward power market structure - allocated in PJM (amended from PJM 2008).



6. Do retail customers face nodal prices?

Nodal regimes offer and impose an increased resolution of power prices across regions. Consequently, there is a possibility that customers located in areas of high congestion or far from generation could be exposed to an increase in the power price because of nodal calculations. Also, it might be difficult communicate to residential customers the reason for price variations within states.

Aggregating pricing 'regions', which averages nodal prices across a region, is a commonly applied option to limit such consumer price risk exposure. Nodal prices are generally calculated and applied for generation and large load, but for retail customers an average of the nodal prices across a region is used. Thus the physically correct representation of the network is combined with a simplified interface for user segments that have limited price responsiveness.

At the start of a nodal-based power market design it is typical to provide customers with a single price across the region. Should final customer demand become more price-responsive and regional congestion increase, then the granularity of prices for retail customers can be increased without creating the need to adjust overall system or contracting structures.

In the US, the FERC generally encourages[5] the disaggregation of load zones (regions based around transmission asset owner(s) and their territories), which are frequently a legacy left over following nodal pricing implementation.

Defining retail pricing boundaries is largely a political process that aims to price retail to wholesale rates fairly. Transmission investment between regions can, to some extent, reduce large price variations and increase homogeneity.

Part of the Californian consultation process to increase the granularity of its load regions included a benchmarking survey with other ISOs. The results provided here describe various routes to structuring the retail price regions and trading wholesale price hubs[6]:

ISO Operating Region	Number of Nodes / Buses	Aggregated Retail Pricing Regions	Wholesale Pricing Hubs
California ISO (CAISO)	3,000	3 regions with 23 sub-regions: covering the majority of one State	-
Midwest ISO (MISO)	1,300	7 pricing regions: covering all or most of 13 States.	6 trading hubs
ISO-New England (ISO-NE)	900	8 pricing regions (match 6 State borders – Mass. has 3 regions)	1 trading hub
PJM Interconnection (PJM)	6,000	18 pricing regions: covering 13 States and Wash. DC.	20 trading hubs
New York ISO (NYISO)	-	11 pricing regions: covering one State.	Weighted region prices used

7. How can we optimize the day-ahead and intraday markets to take advantage of improving wind forecasts?

The quality of wind forecasts improves close to real time (e.g. 4 hours). The effective utilization of large scale wind power therefore requires that the system dispatch is optimized on short time frames.

Iberian experience

The Iberian power market succeeded in keeping demand for balancing services constant despite the large increase in wind deployment and the almost 'island' nature of the grid. This might well be explained by the combination of an integrated approach to wind forecasting and an effective day-ahead and intraday energy market.

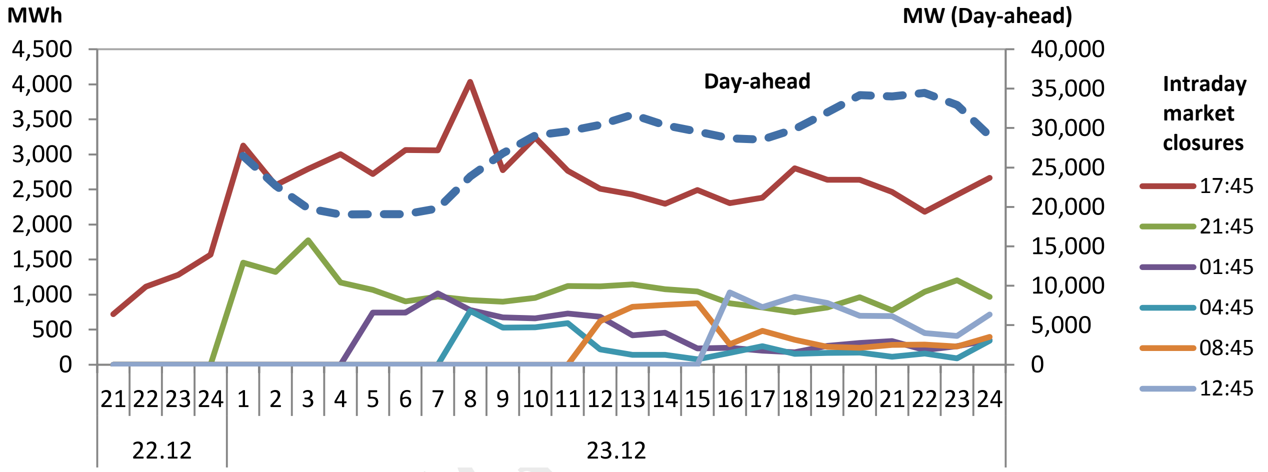
[5] With the Californian ISO, FERC ordered the existing three pricing zones to be disaggregated (Docket number ER06-615-000).
[6] Sources from CAISO "Load Granularity Refinements – Issue Paper", ISO websites, and http://www.ferc.gov/market-oversight/mkt-electric/overview.asp.

The power market OMEL runs a centralized platform that accepts bids and adjustment bids during five defined hours intraday. In the day-ahead market, participants can choose whether to submit energy bid curves, or to submit a complex bid that specifies:

- Indivisibility - minimum operating value;
- Load gradients - maximum ramping rates for power stations;
- Minimum income – ensuring that start-up costs can be recovered;
- Scheduled stop – allowing generation units to gradually ramp down.

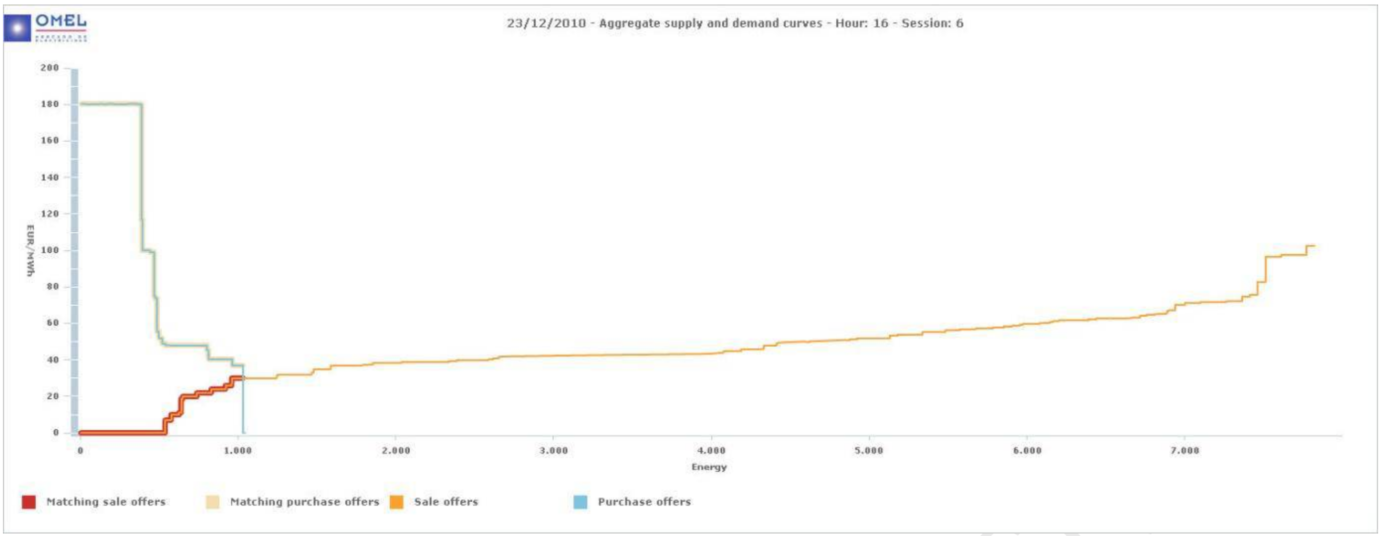
This allows dispatch to be optimized across all units of the system. Subsequent to the market clearing process, six intraday markets operate. Figure 5 illustrates that in each intraday market adjustments to all subsequent hours are traded in a liquid environment.

Figure 5: Traded volumes at day-ahead and intraday market:
OMEL (Spain and Portugal), 23.12.2010.



More important than the volume of observed adjustments for any hour (in response to updated information on wind output and other uncertainties), is the volume of potential supply of flexible response. Figure 6 illustrates the supply and demand for adjustments as offered in the sixth session, closing at 12.45pm, for the hour 4pm to 5pm. As all generators available in the system offer their potential flexibility, even 3 hours before dispatch, additional energy corresponding to 20% of total demand remains available and is offered at prices that would not result in price spikes.

Figure 6: Aggregate supply and demand curves – 23.12.2010, hour 16 – session 6 intraday market closing 12:45. OMEL (Spain and Portugal).



As in the day ahead market, bids submitted to the intraday market can be formulated as energy only bids, or as complex bids specifying load gradient, minimum income (to cover start-up cost), minimum number of consecutive hours required, and (to ensure pump storage does not run out of energy) the maximum energy that can be provided across a set of hours.

In the Iberian market, different prices are calculated for Spain and Portugal if the commercially available transmission capacity between the countries would be exceeded in the case of a single market clearing price. The market clearing process for the energy market, however, does not take into consideration transmission constraints within each of the countries. The Spanish grid operator does bilaterally contract with generators and load to address these internal constraints (redispatch).

US experience

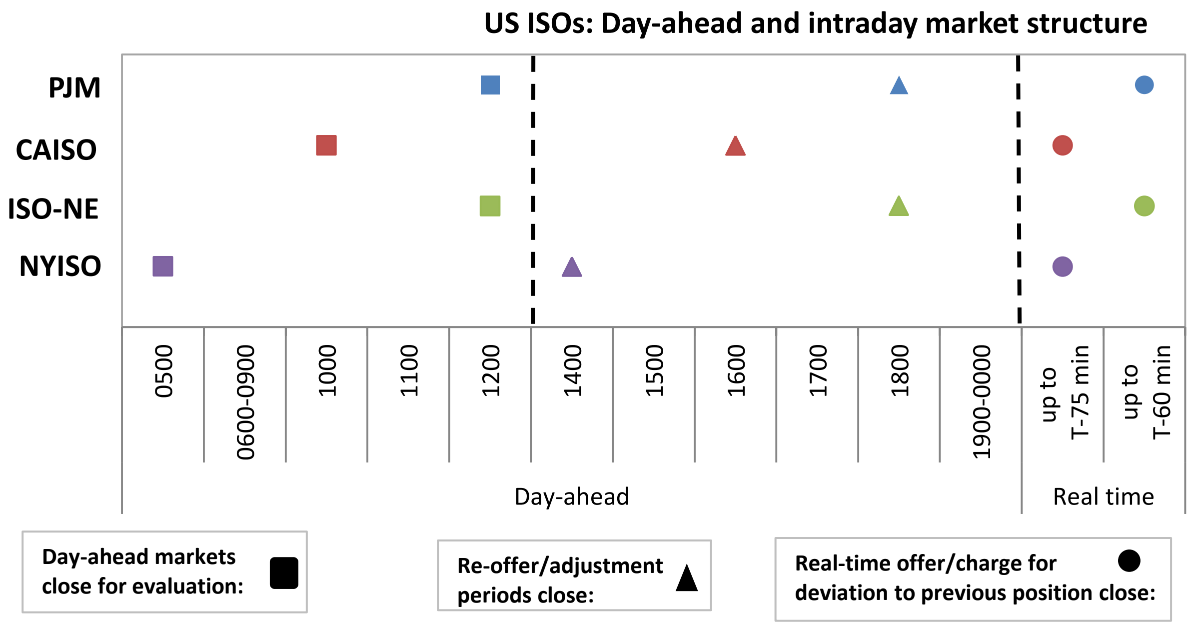
As discussed above, the various US locational marginal pricing (LMP) markets offer an alternative to combine effective congestion management with system wide optimization at the day-ahead and intraday-stage.

As in Spain, US markets offer a common day-ahead and intraday trading platform. Generators can decide on whether to submit firm transaction schedules, energy-only bids or complex bids.

In contrast to the Spanish situation, the market clearing at the day-ahead and intraday level does respect transmission constraints and thus avoids the need for ex-post adjustments (redispatch).

Figure 7 illustrates the time schedules of some of the US ISOs. After the day-ahead market closes, market participants can offer adjustment bids. Similar to the Spanish case, these adjustment bids can comprise energy-only offers or complex bids with a characterization of the technical parameters of power stations or load (ramping rates, minimum run times, etc.). The bids remain valid during the intraday period and can be called up to one hour before real time by the ISO.

Figure 7: US-ISO Day-ahead and intraday market structure (CAISO, PJM, ISO-NE and NYISO).



8. Can nodal pricing regimes accommodate energy from hydro?

When considering the large seasonal hydro reservoirs in the Alps and in Scandinavia, variable generation costs are zero at first sight, but important opportunity costs arise on further inspection. With approximately 5% of capacity from hydro power (PJM, 2009), PJM currently requires each plant operator to submit a cost-based bid, to be used in the case of congestion. Elsewhere, CAISO, with 15% of energy production from hydro, has experience in integrating many small and medium size hydro plants into a nodal pricing regime (California Energy Commission http://www.energy.ca.gov/hydroelectric/index.html).

Technical Details[7]

9. How long does it take to calculate a market result for large systems?

Current PJM market rules have a four-hour window between bid/offer submittal in the day-ahead market and the release of market results. When this limit was established 13 years ago, it was due to a computational limit. Since then technology has improved significantly, meaning that the four-hour window is really a legacy issue that stakeholders have not wanted to address. With the current technology, the market results are produced in less than 30 minutes.

10. What level of information exchange is necessary for secure system operation?

In nodal pricing regimes implemented in the US, TSOs pass system relevant information to the ISO on a frequent basis. This is essential to allow for a security-constrained dispatch optimization. As

[7] Input from Andy Ott, PJM, is gratefully acknowledged.

increasing penetration from wind power can result in large deviations of power flow patterns from historically observed patterns, it is unlikely that the heuristics developed by national TSOs to assess the secure operation of the network remain viable in the future.

In Europe, TSOs only collect and process information in their control zone. Thus, the risk of power failures that could have been avoided through better coordination among neighbouring TSOs only increases (see events on E-ON territory, Austria/Italy border etc.).

The process of integrating the information structure for the continental European grid has failed to deliver satisfactory results throughout the last decade. This can be attributed to the governance situation – full support by all TSOs is required – as much as to the lack of a specific model that clearly specifies the information infrastructure.

To that end, a regime utilizing nodal pricing with an ISO provides a clear framework for the transparent and responsible allocation of information sharing between TSOs and ISO. The ISO has to comply with data protection requirements similar to the requirements imposed on financial auditors, which addresses one of the major obstacles for better system integration – concerns about commercially sensitive information.

Control requirements

Controlling a grid in real time is not just a question of using the right algorithms to foresee the effects of contingencies and appropriate measures for avoiding them. It is also an issue of identifying the current system state: real time measures are available, yet these are not error-free and may be partly inconsistent. Specialized algorithms that aim to estimate the current status of the grid from available measurements have so far been implemented on the TSO level, but transferring this to a European-wide ISO remains a challenging task.

The PJM state estimator (supplied by Siemens) produces a solved powerflow case every 30 seconds in real-time operations. The failure rates are less than 1%, which indicates it is highly reliable. PJM thus has a consistent (AC) powerflow solution to perform real-time analysis every 30 seconds. The PJM billing and settlements is performed on billing quality meter readings that are uploaded daily to allow for comparison of the real-time state estimated measurements to the next day billing quality measurements.

The state estimation error rates for generator and observable substations is less than 0.5%, and the state estimation error rates for non-observable substations is less than 4%.

11. Can ISOs or TSOs better ensure system security?

Power failures in the high voltage electricity network are typically caused by insufficient generation capacity on the network requiring load-shedding, or by failures in generation or transmission operation triggering system blackouts. Historically, vertically integrated utilities were responsible for ensuring both generation capacity adequacy and system stability and security. In liberalized markets, generation adequacy is left jointly in the hands of the market and under the responsibility of regulators. Transmission operators or ISOs are charged with the safe operation of the system: therefore this point is the focus of this discussion.

Throughout the 20th century, the US power system faced more system security incidents than the European system[8]. At this time, all power systems were operated by vertically integrated utilities, and hence a comparison does provide information to assess the performance of different organisational structures.

Major system security events	North America	EU
2003	North-east blackout: - 50 million people affected, 70 GW of generation losses, 8 US states and 2 Canadian provinces. - Reasons: Human error (vegetation), safety equipment failure and lack of ISO coordination cascaded event. - Classed as a one-in-25 year event[9]	Italy blackout: - 55 million people, Italy and Switzerland. - Human error (vegetation) on Italy-Swiss interconnector, lack of TSO coordination cascaded effects.
2006		November blackout: - 15+ million people affected, most of the UCTE continental system including west, east and south-east systems. - Human error, breakdown of operational safeguards, lack of TSO coordination to relay information of actions taken.
2011	February Texas load-shedding: - Much of Texas suffered load-shedding due to insufficient generation capacity. - Abnormally cold weather with scheduled and unscheduled outages. - Irrelevant for ISO versus TSO comparison since the Texas grid is effectively an island. Report found market operated efficiently.	

In the 21st century, with the implementation of vertical unbundling, the different organisational models in the US and Europe can be used to compare system security. With three major events, two in Europe and one in the USA, the quantitative evidence is too small to draw significant conclusions on the performance of the ISO versus the TSO model[10]. In all instances, an initial fault resulted in a blackout across a large region, but it is unlikely that all faults can ever be prevented completely. However, with better coordination and cooperation between system operators (ISOs in the US, TSOs in the EU) the spread of a local incidence to turn into a blackout across a large region can be avoided[11]. This suggests two criteria that need to be assessed when evaluated in further work:

- Is cooperation better among TSOs or among ISOs, and what regulatory measures are available to improve the situation in either case?
- Does the larger area covered by an ISO or by a TSO reduce number of interfaces between agents and improve overall coordination?

[8] Wu, L. et al (2006): *Blackouts: Description, Analysis and Classification*, 6th WSEAS International Conference on Power Systems, Lisbon.
[9] Carnegie Mellon Electricity Industry Center. http://wpweb2.tepper.cmu.edu/ceic/papers/ceic-08-01.asp
[10] Several loss of load events occurred in both the US and EU after liberalisation, but their effects were largely local so excluded from the purposes of the table.
[11] Bialek, J. (2007): *Why has it happened again? Comparison between the UCTE blackout in 2006 and the blackouts of 2003*, IEEE PowerTech Conference, Lausanne.

In summary – the short period of time does not provide a basis for strong empirical evidence. To date, there have been less major incidents with the ISO model than TSO models. In either case, it remains essential that cooperation and coordination between neighbouring operators is improved.

12. Does it suffice to integrate day-ahead markets?

A possible solution to the information handling and control problems could be to confer the responsibility for the day-ahead scheduling (and possibly the intraday planning up to some gate closure time, e.g. 75 min in advance of delivery) to an ISO. However, this would require a clear definition of responsibilities and information exchange procedures between the local TSOs and the ISO. For instance, occurred contingencies as well as counter-measures taken at the local level need to be clearly communicated to the European level in order to avoid inconsistent planning for future time periods.

In the US, the TSOs can focus their effort on grid investment, maintenance, and operation, and they have more stable revenue streams that reduce risk and capital costs for existing and new grid infrastructure. The ISO gathers information from national/regional TSOs on the state of the network, accepts bids/schedules from power generators, calculates the market clearing prices, shares them with market participants, and informs TSOs about aspects relevant for their operation of the network.

The territory covered by PJM avoided the large scale black out across the North East of the US and some Canadian provinces, because an integrated real time dispatch algorithm provided timely and accurate information that allowed for quick responses. This might have contributed to the positive track record of nodal pricing. Where liberalized markets have implemented nodal pricing, they have not suffered any major black outs.

Institutional details

13. Who owns the ISO?

In Europe the single ISO model has been discussed in recent years from the perspective of network ownership/regulation, but the aspects relating to the operation of the network, as discussed in the context of nodal pricing (that would gradually be expanded across Europe), have been rarely explored.

Instead, the European discussion has often focused on whether regional power exchanges would be transformed into the ISO, that is, whether ownership of the ISO would remain in the hands of the initial power exchange owners. In some parts of Europe, the TSOs (Nordel, for example) own considerable shares in the power exchange. Yet in other parts, like in Germany, this is not true. Therefore, transferring important parts of the business of power exchanges to the TSOs will negatively affect the shareholders of the power exchanges, and they might claim compensation or oppose the changes.

To a large extent these concerns have been avoided in the US by designing ISOs as not-for-profit entities. This is possible because nodal pricing defines a transparent dispatch algorithm; therefore no incentives are required to ensure efficient trading behaviour by the ISO. The ISO operates on a regulated income that is charged to users. All congestion revenue is recycled to owners of FTRs/AARs, and ultimately to network users through a reduction of network tariffs. Thus, the ISO is not exposed to trading risk and does not require an asset base to insure against losses.

By clearly defining the functions of an ISO as the operator of day-ahead and intraday markets, the provider of long-term FTRs, and the allocator of long-term ARRs, it can be ensured that commercial energy trading organisations can compete fairly, resulting in a competitive and liquid market across the regions (see question 3).

It is striking that, in Europe, national or regional power exchanges like EEX, APX, and Nordpool have been granted a monopoly position by receiving the right to implement the market infrastructure for market coupling with neighbouring countries. Thus they have preferential access to clients that have to use their platform to pursue effective day-ahead trading (or are even obliged to do so as in the case of APX). Financial long-term contracts need to be based on the market price that emerges from these national monopolies. As the liquidity and price at these national power exchanges cannot be guaranteed for the long-term, financial long-term contracts are defined with physical clearing based on the national power exchange as a fall-back option. This creates strong incentives to use the clearing platform of national power exchanges, further strengthening their dominant position. The ISO model offers a more market-oriented solution with a clear separation between the natural monopoly role of a day-ahead/intraday trading platform in electricity markets and the commercial basis for long-term trading.

Eventually, European competition authorities might require unbundling of the provision of the platform for day-ahead and intra-day trading (natural monopoly) from longer term trading activities and services (competitive). A quick transition as part of the implementation of an ISO could allow power exchanges to translate their established brand and trading expertise into the new world rather than engage in a prolonged dispute with regulatory authorities.

14. Is it possible to gradually extend an ISO?

In order to progress more rapidly with the introduction of a European ISO, one might envisage establishing an ISO, as a first step, only in parts of Europe. Yet in this case, the flows to neighbouring regions are still not managed optimally. Would this imply that many of the efficiency gains achievable within a limited zone may disappear due to flawed procedures for handling flows across its border?

PJM has made significant progress in implementing an inter-regional, near real-time, power flow management process between PJM and MISO. Transmission constraint information is shared in real-time operations every 15 minutes with MISO, and the 5-minute security-constrained dispatch software iteratively resolves the joint constraint set such that our real-time nodal pricing results respect the inter-regional constraints.

Thus, a regional ISO can be initially established, but a clear and harmonized protocol is necessary to facilitate information exchange across regions. With increasing wind penetration, the efficiency gains from integrating these ISOs will increase.

Descriptors

CPI Area of Focus: Implementation
Sector: Power and Energy
Region: Europe, USA
Keywords: Power market design
Contact: Karsten Neuhoff, karsten.neuhoff@climatepolicyinitiative.org

About CPI

Climate Policy Initiative (CPI) is a policy effectiveness analysis and advisory organization whose mission is to assess, diagnose and support the efforts of key governments around the world to achieve low-carbon growth. CPI is headquartered in San Francisco and has research centers around the world which are affiliated with distinguished research institutions. Research centers include: CPI at Tsinghua, affiliated with the School of Public Policy and Management at Tsinghua University; CPI Berlin, affiliated with the Department for Energy, Transportation and the Environment at DIW Berlin; CPI Rio, affiliated with Pontifical Catholic University of Rio (PUC-Rio); and CPI Venice, affiliated with Fondazione Eni Enrico Mattei (FEEM). CPI is an independent, not-for-profit organization which receives long-term funding from George Soros.