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DRAFT

Chapter 5. Transmission and Wholesale Power Markets

1. Introduction

For almost a decade FERC has been attempting to create competitive wholesale electricity markets by opening the grid to competing generators, promoting regional transmission markets and by encouraging investment in transmission capability.[1] If its policy initiatives succeed, FERC would transform large areas of the country into "Common Markets" for electricity commerce. The grid would become a network of superhighways for markets, seamlessly moving power across the country to reduce costs and improve reliability.

Despite FERC's efforts, much of the United States remains more like a collection of loosely connected toll roads than a network of superhighways. Unlike the interstate highway system the high voltage grid has hundreds of owners, including governments and investor owned utilities, each manning a tollbooth. Each transmission company built a piece of the grid to serve its retail customers (native load). Interconnections between systems were primarily for improving reliability and for sharing occasional surpluses. The grid was not designed and built with the idea of supporting large regional markets.

Electricity markets are dependent upon the grid to connect buyers and sellers and to consummate trade agreements. When lines serving Chicago, for example, are congested, outside suppliers are unable to deliver additional volumes. Shortfalls in meeting demand must then be met by higher cost local generation. Generators located within such load pockets are well positioned to charge prices well above their relatively high (marginal) costs. Congestion effectively fragments markets to the detriment of competition.

Even when transmission resources are sufficient to move power to higher price areas, buyers and sellers may be unable to carry out mutually beneficial trades. That is because each region (control area, ISO/RTO and NERC region) has its own rules, operating practices and charges for importing and exporting power. The administrative difficulties and costs of coordinating power flows across system boundaries can be serious obstacles to trade. Resolution of these "seams" issues is a prerequisite for further market integration.

[1] FERC Order 888 (1996), FERC Order 2000 (2000), Notice of Proposed Rulemaking Standard Market Design (August 2002), FERC Notice of Proposed Rulemaking, Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid, Docket No. PL03-1-000, Issued January 15, 2003.

This chapter considers data useful for gauging the grid's support of larger, more competitive markets. Data are needed to answer questions such as: Are generators able to access and connect to the grid? Are the costs and quality of transmission service non-discriminatory and reasonable? Are bottlenecks, load pockets and large congestion costs prevalent? Are the costs of moving power across system control boundaries large and growing? Is power readily flowing from low cost to high cost areas? Are there persistent, large differences in regional wholesale prices? Are FERC's policy initiatives succeeding?

The available data are only evidence that the grid is (or is not) being used in ways that are more (or less) consistent with expanding markets and competition. They are not absolute measures of the size of markets and the trade possibilities the grid defines.

2. Measuring the Grid's Impact on Wholesale Markets

The fundamental measures of the grid's impact on markets are the potential size of the markets (defined by the grid's capabilities) and the volumes of economic trade it could support. Economic trade is undertaken in response to price differences: the greater the difference in price, the greater are the volumes tending to flow to the higher priced market. Market organization, regulation and transaction costs can cause actual market size and trade volumes to be substantially less than their potential.

Electrical models of the grid are generally necessary to determine which suppliers are physically able to serve markets.[2] Unlike highway transportation, geographic separation neither measures transmission "distance" between generators and markets nor explains its cost. Electrical models are also necessary to determine how much power could be moved from suppliers to markets. Unlike a highway, a line may be congested (unable to carry more energy) when carrying only a fraction of its rated capacity. The Federal Government does not maintain reference electrical models of the grid and, therefore, has limited means to establish potential market size.

Practicable measures focus on data showing the grid's support of competitive markets. Among these historical data series are:

1. Grid access and generator connection
2. Cost and quality of transmission service
3. Load pockets and transmission bottlenecks
4. Congestion Costs
5. Seams costs (trade barriers)
6. Economic trade and regional price differences.

Access refers to a generator's ability to put power into the grid. Denial of service forces generators out of the market. Statistics on access requests and service denials show the grid's support of generator competition and can reveal unequal treatment of market

[2] FERC has used confidential company sales information in merger cases to establish historical market boundaries. That data neither identifies all potential suppliers nor does it show the effect of changes in grid configuration and use patterns on the list of potential competitors. Chapter 3 contains a brief discussion of electrical models.

participants. Generator connection data show the grid's accommodation of new entrants, all eventually requiring access to compete.

The quality of transmission service refers to the kind of service available to customers. Service can either be point to point or network service. In addition service can either be firm or interruptible. Firm service all but guarantees transmission. Interruptible service can be suspended (curtailed) for a variety of economic and operational reasons. In most of the United States firm service is negotiated between transmission owners and customers. In PJM and the New York ISO's transmission is firm so long as customers are willing to pay any congestion charges. In PJM customers can buy financial transmission rights (FTRs), also called fixed transmission rights, which allow the holder to recover congestion charges he incurs in flowing power between the two points specified in the FTR.

Generators need firm service to sell into ISO capacity markets and to assure customers they can deliver contracted energy.[3] Data showing that firm transmission service is increasingly available, less costly and that curtailments are decreasing would be evidence that the grid is better supporting commerce.

Bottlenecks refer to constraints on the grid's physical ability to deliver power while respecting security limits. Congestion costs are a measure of the cost of these limits. Data showing temporal declines in bottlenecks and congestion costs would indicate that transmission is becoming less of a constraint to market integration and competition.

Seams costs refer to administrative, coordination and other institutional obstacles to trade between control areas. To ensure reliability control area operators require the sending and receiving parties to schedule power flows and agree on price and other terms in advance. Outsiders typically have to make scheduling arrangements and pay fees that insiders do not face. PJM imposes a fee for exporting power outside its borders. These coordination and pricing arrangements-"seams issues"-increase the cost of moving energy between markets and limit market integration.

Economic trade refers to the movement of power between markets in response to price differences. Economic trade within and across regions is a powerful force both for limiting the ability of local producers to raise prices and for efficient resource allocation. When the local price of petroleum and other energy sources exceeds the outside price by more than transportation costs, imports increase. By analogy data showing large electrical volumes regularly flow from lower to higher price areas would suggest the grid is supporting competition.

Matters are not so simple with electricity. As mentioned in Chapter 3, electricity on an AC system cannot be directed from individual generators to individual customers. Instead, generators put power onto the grid and their customers take power off. Some

[3] Customers can be responsible for acquiring transmission. Load serving entities can buy FTRs to insure their agreements with generators.

power flows across boundaries are inadvertent. These loop flows do not represent commercial transactions, but they can be large.

Another minor complication is that electricity can flow from higher priced to lower priced areas. In extreme cases, which do occur in practice, customers are paid for taking more power. This inversion of normal commercial practice happens because transmitting power to lower price areas can at times reduce even higher congestion costs elsewhere in the grid.

Even with these anomalies a strong tendency for significant power volumes to flow in the direction of higher price would suggest the grid is supporting economic trade. Growing economic trade and narrowing price differences would be consistent with the grid better supporting market competition.

However useful these data are for identifying market trends, and documenting current conditions, they can only record what was. By themselves they are imperfect guides to how electricity market size and trade potential change in response to changes in the grid's configuration, its management and its economic organization. Valid inferences about the quantitative impact of future and hypothetical conditions require realistic electrical models.

3. Data Showing the Grid's Support of Markets

Access: FERC's Open Access Same-time Information System (OASIS) is the primary source of data regarding grid access, available capacity, transmission rates and other transmission data. Each public utility or its agent that owns, controls or operates transmission facilities in interstate commerce is required to post data prescribed by FERC and to make it available to market participants, FERC, state regulators, and the public.[4] FERC requires the data to be available on the site for 90 days and retained for three years.

There are currently 25 OASIS website nodes that serve as gateways to 147 transmission provider websites.[5] The numbers of firms listed in a node varies; The Western States Coordination Counsel lists 30 transmission providers, the ECAR node lists 3. Some transmission providers not regulated by FERC (non-jurisdictional entities) voluntarily maintain OASIS websites. Among them are eight firms in ERCOT, the Bonneville Power Administration, The Western Areas Power Administration, and the Sacramento Municipal Utility District. The Tennessee Valley Authority does not maintain an OASIS site

Entergy's OASIS site illustrates the kind of data that is available. The site contains information on type of service requested, volume requested, number of hours sought, price of service, affiliation with Entergy, and whether or not the request was granted. Table 5-1 reports the disposition of 1,216 requests for non-firm, point-to-point service requested through Entergy's OASIS site for the month of June 2003. About 96 GW of

[4]See FERC Order 889, Open Access Same-time Information System and Standards for Conduct, Final Rule (issued April 24, 1996), Docket No. RM95-90-000. See also, OASIS Standards and Communications Protocols.
[5] The address of the central clearing house is www.tsin.com.

transmission capacity was requested by 24 entities, of which a total of 3.7 GW capacity (about 4 percent of that requested) was refused. Of the 24 companies requesting service, two were affiliates of Entergy, which jointly filed 696 (57%) of the requests, leaving 22 unaffiliated entities with 520 of the requests. Entergy affiliates requested capacity reservations in twice the volume on average as the non-affiliates. Non-affiliates were refused more capacity in aggregate, and their total of 1,870 MW refused constituted 7% of their total requested capacity.

Table 5-1. Non-firm Point-to-Point Transmission Service, Entergy, June 2003

	Affiliates	Non-Affiliates	Total
Entities	2	22	24
Requests	696	520	1,216
Requests Refused	20	27	47
MW Requests	69,134	26,727	95,861
MW Refused	1,793	1,870	3,663
Avg. MW Request	99	51	79
Avg. MW Refused	90	69	78
% MW Refused	2.6%	7.0%	3.8%

Source: Entergy OASIS website, http://oasis.e-terrasolutions.com/OASIS/EES

Although FERC mandates their minimal content, OASIS sites vary considerably in their look and feel. As part of the research for this report, the author asked FERC staff to extract comparable data from several OASIS sites. The FERC analyst reported that identical queries succeed or failed depending on the site. Each had its own language. She found sites would not allow the data itself to be downloaded; some would not download data in a standard ".cvs" or spreadsheet file. There is no official database that maintains and archives time series of the information on the OASIS sites.

New generator entry: EIA form 860 reports when generators connect to the grid and their major characteristics, including location, size, major fuel and ownership. Table 5-2 reports 173 GW of new capacity, most of it gas-fired combined cycle and turbine units, added since 1995.[6] This represents a 23 percent-increase over the 1994 national total capacity of 763 GW.[7] The table also shows that most of the capacity expansion has occurred in the non-utility sector, specifically Independent Power Producers that do not own transmission facilities.

[6] Energy Information Administration, Form EIA-860(2002), "Annual Electric Generator Report."

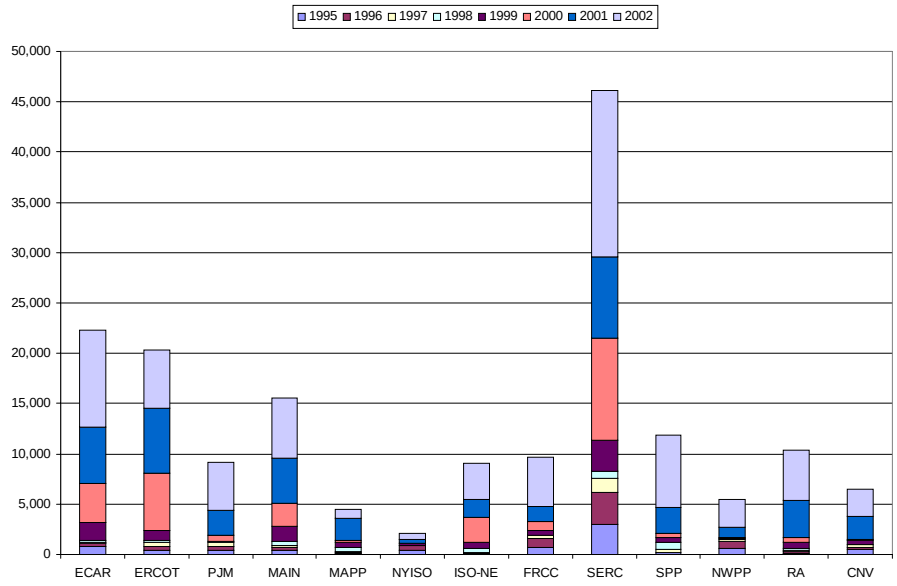
[7] Energy Information Administration, ***Electric Power Annual 2001***, (DOE/EIA-0348(2001), March 2003, Table 2.1, p. 16.

Table 5-2
(MW Summer Capacity, number of units)

Owner type	1995	1996	1997	1998	1999	2000	2001	2002	Total
Investor-Owned	3,774	2,205	1,247	636	1,788	5,046	6,904	4,210	25,809
	53	43	18	14	24	83	62	30	327
Publicly Owned	1,212	2,676	811	602	1,472	2,253	3,744	5,353	18,124
	40	63	44	61	132	114	111	174	739
IPPs	530	480	309	597	5,686	17,707	25,248	52,000	102,556
	53	44	61	68	138	243	370	553	1,530
Other Nonutility	2,165	2,148	1,257	1,612	1,565	2,319	6,669	8,735	26,470
	81	75	44	50	57	58	62	67	494
Total Capacity	7,681	7,510	3,623	3,447	10,511	27,325	42,565	70,298	172,960
Total Units	227	225	167	193	351	498	605	824	3,090

Figure 5-1 reports the new units are widely distributed by NERC region. SERC, already the largest region from a capacity standpoint, shows the most new generation with more than a quarter of the total new capacity. ECAR's expansion is roughly proportionate to its size. ERCOT shows a disproportionately large amount of new capacity relative to existing capacity. This reflects in part the replacement of older, less efficient steam units with new combined cycle technology. California (California-Southern Nevada Power), in response to the crisis of 2000-01, shows much greater activity in 2001 and 2002 than in the years 1995-2000. The NYISO reports relatively little additional new capacity, indicating that either new units or expanded transmission access will be needed to meet increasing demand in the next few years.[8]

Figure 5-1



[8] See, for example, New York Independent System Operator, *Power Alert II, New York's Persisting Energy Crisis*, March 27, 2002; also NYISO, *Power Alert III, New York's Energy Future*, May 2003. Available at www.nyiso.com.

EIA data neither shows how much generators pay to connect (direct and for system enhancements) nor the time required between application for service and connection. EIA's connection data is in the public domain.

Cost and Quality of Transmission Service: OASIS is also the primary source of data on the availability and cost of firm and interruptible service. Entergy's web site again provides an example. [9]

5-3. Entergy Transmission Service Rates (June 1, 2003)

Service	Firm		Non-Firm	
	Price	Units	Price	Units
Hourly On-Peak (hour ending 0700 through hour ending 2200 on Monday through Friday)	NA	NA	$3.15	MWH
Hourly Off-Peak (all other hours)	NA	NA	$1.50	MWH
Daily On-Peak (Monday through Friday)	$50.00	MW-DAY	$50.00	MW-DAY
Daily Off-Peak (Saturday and Sunday)	$36.00	MW-DAY	$36.00	MW-DAY
Weekly	$252.00	MW-WEEK	$252.00	MW-WEEK
Monthly	$1090.00	MW-MONTH	$1090.00	MW-MONTH
Long Term (one year or longer)	$1030.00	MW-MONTH	NA	NA

Entergy does not offer long-term non-firm service or hourly firm service. In addition to these charges, transmission customers must buy ancillary services from Entergy at its posted rates. They must also make up for transmission losses with additional generation (3% of the delivered volume).

What is not available on OASIS is how much individual generators and load serving entities actually pay for transmission of wholesale energy[10]. In some areas the costs include explicit congestion fees and the costs of transmission rights in addition to the kinds of charges Entergy lists. Annual statistics on how much power utilities wheel and revenues from wheeling are available, see chapter 4. It is not possible to tell whether average annual data well represents the charges wholesale customers face at peak times, or seasonally or for all locations served by the service provider.

[9] Entergy's Open Access Transmission Tariff, filed March 20, 2001, is also available on its web site. The tariff runs 452 pages.

[10] EIA collects delivery charges and megawatts delivered to unbundled **retai**l customers on the EIA 861, Schedule 4, Part C.

OASIS does not report on how much of each market participant's generation or demand volume is covered by firm transmission. Although a customer has arranged for transmission, either firm or interruptible, the power may not be delivered, i.e. it may be curtailed. Chapter 3 reports that the North American Electric Reliability Council's (NERC) transmission loading relief (TLR) system records but does not routinely report curtailment data to government and data are only available for the Eastern Interconnect. Trends in the frequency and size of curtailments are measures of the quality of transmission service.

Bottlenecks: ISOs, transmission owners and market participants are generally knowledgeable of bottlenecks. However, documented analyses of these constraints are mainly available from ISOs. NERC's periodic reliability assessments (see Chapter 3) identify load pockets and bottlenecks. To some extent NERC's identifications are based on publicly available TLR data. The analytical basis NERC uses for identifying other bottlenecks is not generally available.

Under contract to the DOE, the Consortium for Electric Reliability Technology Solutions (CERTS) surveyed six ISO/RTOs to identify bottlenecks and load pockets in their areas.[11] Their results, summarized in Table 5-4, are representative of the kinds of data that are available from those organizations.

Table 5-4. Major Bottlenecks

	Widespread Grid Reliability Problems	Risk of Significant Consumer Cost
CAISO	San Diego Area and the San Francisco Peninsula	Path 15
ERCOT		South to North Texas and South Texas to Houston
NYISO		Central East, Leeds-PV and NYC/LI Cable Interface

[11] CERTS, U.S. Department of Energy Transmission Bottleneck Project Report, March 19, 2003.

ISO-NE	SW Conn.-Norwalk, NE Mass/Boston Area and NW Vermont	
PJM		NW Penn., West of Wash. D.C., Delmarva Peninsula, West and East 500kV Interface

Source: CERTS, U.S. Department of Energy Transmission Bottleneck Project Report, March 19, 2003., page 16

The CERTs study also reported estimates of the costs of some of the projects for relieving congestion. The study does not report how much these investments would be expected to save.

Table 5-5. Project Cost to Partially Relieve Congestion

ISO	Project	Cost (Millions)
CAISO	Path 26	$306
	Imports to San Diego	$252
ERCOT	Two 345 kV lines from West Texas to North Texas	$140
MISO	New high voltage lines	$7,000
	Gains Substation – add a second 345/138 kV transformer bank – needed to serve load growth in the area of Grand Rapids, Michigan	$7
NYISO	Marcy-New Scotland 345 kV circuit – line originally built for 765 kV could be converted from single to double circuit	$75
	Rebuild two 115 kV lines out of Leeds to 345 kV	$225
ISO-NE	Build a 345 kV loop around the Southwestern Connecticut area (Phase 1 and 2)	$600
	Reinforce Northwest Vermont load pocket	$125
PJM	Adding 500/230 kV transformers at Doubs Substation (Northwest of Washington, DC)	$22

Source: CERTS, U.S. Department of Energy Transmission Bottleneck Project Report, March 19, 2003., page 16

Many transmission bottlenecks cannot be identified with TLR data. The Western United States does not use TLRs to manage congestion. A TLR may also indicate overbooking rather than a physical limit. Overbooking is mainly a reflection of the limits to

forecasting transmission requirements accurately. Systems that are trying to facilitate trade may attempt to operate close to their security limit. Systems that do not encourage trade may understate how much transmission capability is available. TLRs have not been exercised in the Southeast; they are common in the Midwest. Commentators disagree on the reasons for the difference.[12]

Congestion Costs and Revenues: Congestion costs and revenues are measured in at least three ways. System re-dispatch cost is the increase in total system operating cost due to congestion to meet a fixed level of demand. Redispatch costs are typically captured in *uplift* charges. Mainly these charges occur because higher cost, but better located, generators must be run to get around transmission constraints. The *economic cost* of congestion is the loss in net benefit and is the same as uplift cost when demand does not depend on price. *Congestion revenue* is the difference in the prices at the sending and receiving end times the flow on the line. Congestion revenue is analogous to a transportation charge but is in fact a particular kind of scarcity rent. The location specific prices needed to calculate congestion revenues are generally available for only a few areas, notably the Eastern ISOs. Several organizations have reported the aggregate of some redispatch costs and congestion revenues.

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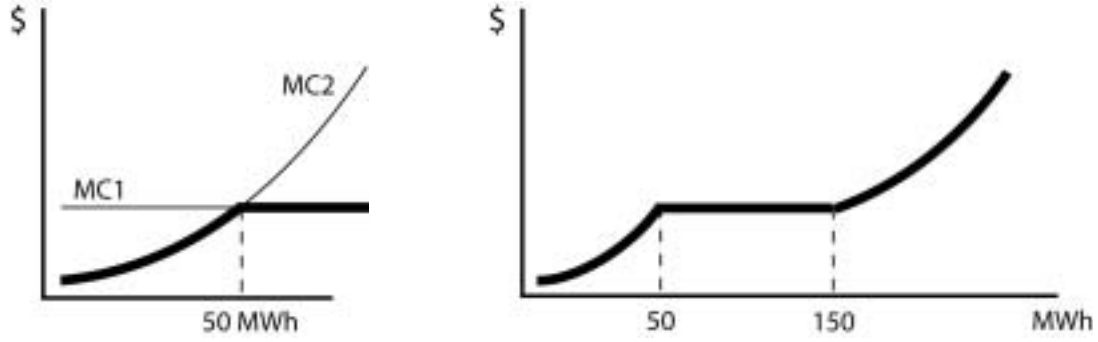
Text Box

Redispatch, Congestion Revenue and Congestion Cost

Re-dispatch costs, congestion revenues, congestion cost (loss of producers' and consumers' surplus) and uplift costs are caused by constraints on the grid's ability to move power from lower to higher cost areas. The following examples illustrate those concepts.

Panel (a) shows two regional supply curves (marginal cost curves, MC1 and MC2): the thick line is the market supply curve. For simplicity assume all demand is in region 2. If there were a 100MW power transfer limit between them, the aggregate supply curve in region 2 would be that shown in Panel (b). If there were no transfer limit, the supply curve in region 2 would extend following the dotted line Up to 50MWh, Region 2 meets its demand with its lowest cost generators; for demand levels up to 150MWh those generators are supplemented with imports from region 1.

Panel (a) Panel (b)

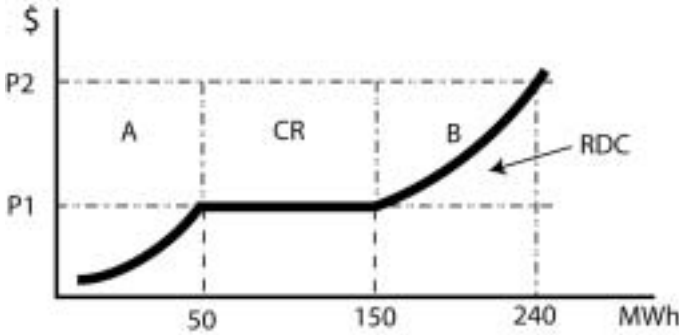


[12] See for example, Canto, Laura and et al, **Beware Transmission Data-Often They Are Not What They Seem to Be**, CERA, June 2003

When demand exceeds 150 MWh, say 240 MWh as in panel (c) imports cannot be increased, and Region 2 has to run its higher cost generators. Redispatch cost is the difference between the lowest cost of meeting demand with and without the line constraint. When demand is fixed, redispatch cost is congestion's economic cost. Redispatch cost is shown in Panel (c) as the area RDC.

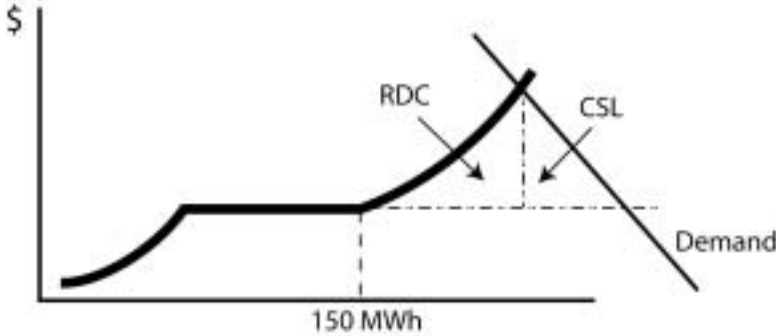
Congestion causes consumer expenditure to increase by more than redispatch cost. Marginal cost in region 2 is P2 and marginal cost in region 1 remains at MC1=P1. In a competitive market, price equals marginal cost. Congestion together with marginal cost pricing, causes consumer expenditure to grow from P1x240 in the unconstrained case to P2x240, for an increase of (P2-P1) x240. As shown in Panel (c), the additional go to generators as increased profit, areas A and B, and compensation for redispatch cost, RDC. The remaining portion of the increased expenditure goes to transmission owners (or holders of financial transmission rights) as congestion revenues, indicated by area CR, which is the price difference times the flow (P2-P1) x100.

Figure (c)



When demand is sensitive to price, congestion reduces the benefits from consuming electricity. Since congestion increases electricity price, customers consume less and forego the benefits of maintaining their electricity use. Congestion's economic cost is the sum of lost consumer benefit and redispatch cost. Those are shown in Panel (d) as the sum of the areas under RDC, re-dispatch cost, and CSL, consumer surplus loss.

Panel (d)



Uplift charges are the specific fees that systems use to pay generators to compensate them for agreeing to be re-dispatched. How these uplift charges are determined varies. In the UK's original pool, generators who are not allowed to produce as much as they would like at the uniform system price are paid an estimate of their foregone profit; those required to produce more at the uniform price are paid to cover their additional costs. Whatever cost/profit loss scheme is used to compensate generators, the increased revenue from customers is more than adequate to fund the payments.
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It is rarely necessary to curtail generation under locational prices since locational prices equate supply and demand in such a way that all transmission limits are met. And they are adjusted in real time in response to system conditions. In the rest of the Eastern United States service curtailments are used to enforce transmission limits. That means observed wholesale prices (when they are available) do not reflect current transmission constraints-the prices net of transmission charges in the sending area are too high and those in the receiving area too low. The congestion revenue (observed price difference times flow) calculated with observed prices is too low. In an attempt to correct for that understatement of congestion revenue, FERC and NYISO have estimated system re-dispatch costs in the receiving area. They then add their estimate of system re-dispatch costs to observed congestion revenue.

Table 5-6 summarizes estimates from four ISOs for their areas and from FERC for the Eastern Interconnect.

Table 5-6. Summary of Congestion Costs Reported by ISOs and FERC

	Period	Congestion Costs Million of Dollars	Congestion Cost-Calculation Method(s)
PJM [1]	1999	$53	Congestion Revenues
PJM [1]	2000	132	
PJM [1]	2001	271	
PJM [2]	2002	430	
ISO-NE [3]	5/99-4/00	$99	Uplift Charges [4]
ISO-NE [3]	5/00-4/01	120	
ISO-NE [5]	2003	50 – 300	System Re-dispatch Payments
CAISO [6]	2000	$391	Congestion Revenues
CAISO [6]	2001	107	
CAISO [7]	2002	42	
NYISO [8]	2000	$1,240	System Re-dispatch Payments + Congestion Revenues
NYISO [8]	2001	570	
NYISO [9]	2000	517	Congestion Revenues
NYISO [9]	2001	310	
NYISO [10]	2002	525	
FERC [11]	6/00-8/00	$891	System Re-dispatch Payments (partial) + Congestion Revenues

[1] PJM Interconnection, *State of the Market Report 2001* (PJM 2002)

[2] PJM Interconnection, *State of the Market Report 2002* (PJM 2003)

[3] ISO New England (ISO-NE), *Annual Markets Report* (ISO New England 2002a)

[4] ISO New England's congestion cost calculation method was modified in March 2003.

[5] ISO New England, *RTEP02* (ISO New England 2002b)

[6] California Independent System Operator (CAISO) *Market Analysis Reports* (CAISO 2000, 2001a)

[7] CAISO, *2002 Annual Report on Market Issues and Performance* (CAISO 2002)

[8] *New York Congestion and Physical Constraint Cost Estimates* (POWERGEM 2002)

[9] *2001Annual Report on the New York Electricity Markets* (Patton and Wander 2002)

[10] *2002 State of the Market Report: New York Electricity Markets* (Patton 2003)

[11] Federal Energy Regulatory Commission (FERC), *Electric Transmission Constraint Study* (FERC 2002)

Source: Lesieutre, Bernard C. and Eto, Joseph H, Electricity Transmission Congestion Costs: A review of Recent Reports, October 2003. DOE Contract No. DE-AC03-76SF0098.

Except for the cited FERC study, official data do not report estimates of redispatch cost, congestion cost and congestion revenues outside of the ISOs. The estimates available for ISO's are a mostly incomparable collage of uplift charges, re-dispatch costs, congestion revenues and a total consisting of some re-dispatch costs and some congestion revenues.

Seams Costs: Except possibly for the ISO/RTOs there are no official data that show the actual costs, direct and indirect, uniquely associated with moving power across control or ownership boundaries. Price differences between the sending and receiving area may reflect, but do not identify, the particular costs of crossing boundaries.

Economic trade and regional price differences: Economic trade is undertaken to profit from price differences between areas. The basic data for documenting economic trade are wholesale price differences and the corresponding trade flows.

Wholesale trade is a mix of very short term and long-term deals. Most wholesale trade occurs in price markets and the prices are not public.[13] Table 5-7 shows EIA data on sales for resale, essentially wholesale trade. In the 6 years following Order 888, wholesale trade increased 65 %, at a continuously compounded growth rate of 8.4 % per year.

Table 5-7

Year	Sales for Resale (Thousand Megawatthours)
2002	2,747,015

[13] FERC's new Electricity Quarterly Report collects prices associated with individual wholesale trades. It may be possible to use this data to estimate market prices for specific regions. In addition to volumes EIA collects annual data on revenues from sales for resale. Dividing revenue by volume yields a volume weighted average annual price, or the same thing, average revenue for sales for resale.

2001	2,893,382
2000	2,325,652
1999	1,977,753
1998	1,914,916
1997	1,838,539
1996	1,656,090
1995	1,495,015
1994	1,387,966
1993	1,387,137
1992	1,284,273
1991	1,250,314
1990	1,115,946

Source: EPA 2002, pg 34.
EPA 2001, pg 36.

Northeastern ISOs and California have public real time markets for wholesale energy and publicly report prices. The Eastern ISOs also have day-ahead markets with publicly reported prices. As shown in Table 5-8 spot markets ("real time" markets) are an important source of supply in the Northeastern ISOs.

Table 5-8. Spot market Sales (% of Demand)

Year	New England	New York	PJM
1999	13 [a]	-	15
2000	23	41	18
2001	24	47	21
2002	32 [b]	48	-

[a] May – December
[b] January – November
sources: ISO New England Monthly Market Report, December 1999-2002; New York Independent System Operator Monthly Report, December 2002 and December 2000; PJM State of the Market Report 1999 – 2001.

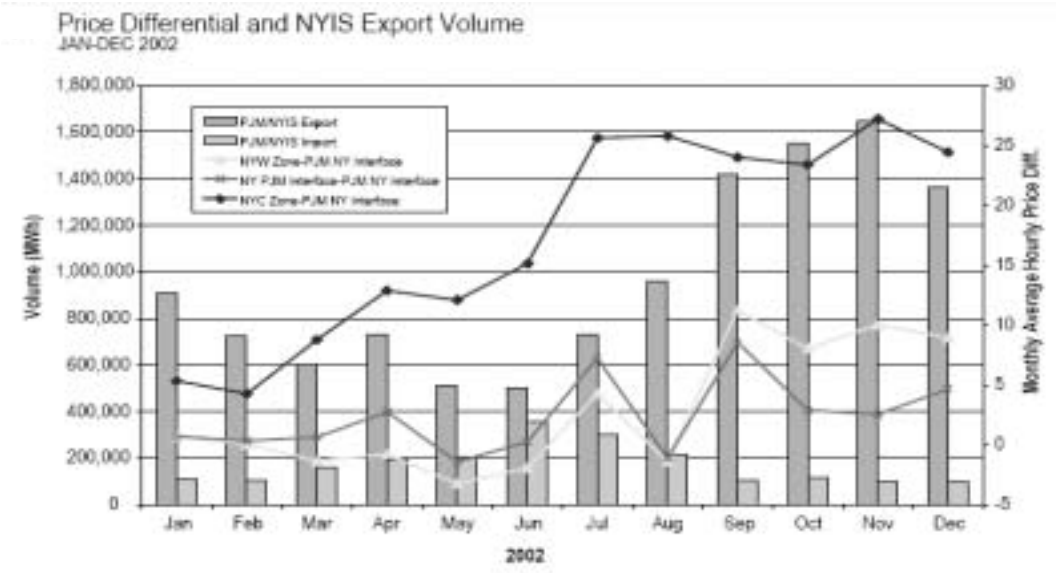
PJM reports relevant price and power flow data for its trade with the New York ISO. About 85% of PJM's gross imports and 93% of its exports occur in the real time market. Differences in spot market prices at the borders are clearly appropriate for valuing trade opportunities.[14] In addition to spot prices, PJM reports net exports to New York. Since both have locational prices it is possible to calculate the differences between the PJM and New York market price at the borders and to associate price differences with power flows.

During 2002, monthly exports to the New York interface ranged from about 100,000 MWh (June) to over 1,500,000 MWh (November). Importantly the volume of exports generally increases as the monthly average hourly difference in the New York and PJM

[14] PJM, 2002 State of the Market, page 62.

price, the price differential, increases. Figure 5-2 shows the export volume to New York and the average hourly price differential for 2002.

Figure 5-2



That exports increase along with the price differential suggests that competition is working to some extent. It does not explain why there is a significant price differential.

The data do not support similar displays for other ISOs. California's adjacent markets do not report market price in official data. ERCOT does not trade outside its boundaries. New England and New York have substantial trade with Canada at negotiated prices. New England trades with New York but until recently it did not use locational prices. Consequently, the "at the border" price differences do not necessarily reflect economic values. There are no official wholesale market price data for PJM's trading partners, outside of New York.

Outside of the ISOs wholesale energy prices are not public. EIA does not collect wholesale electricity prices except as a volume weighted average.[15] FERC is now

[15] EIA calculates a volume weighted wholesale price as average revenue (revenues divided by volume sold). Volume weighted average wholesale prices are often mistakenly interpreted as market price. See for examples, Lynch, Lorreta , *An unfair jolt to consumers*, San Francisco Chronicle, December 12, 2003, figure description identifies average revenue as price. Also, U.S. General Accounting Office, *Electricity Restructuring*, GAO-03-586, Appendix 1, page 49 asserts that the EIA-826 "..is the only timely source of information on the price and volume of power sold…". The reference is to volume weighted price revenue, not market price. Market prices at every hour of the day may be identical in two areas but their average revenue "price" would be the same only if both areas have the same share and average price of long-term contracts. Even then, if customers in one area consume relatively more when prices are high, the average revenues would be higher in that area. Electricity's market prices changes a great deal during the day and seasonally, see Chapter 6, so the distinction is not academic. Literally no one may be able to buy or sell power at its weighted average price.

attempting to collect the prices associated with individual spot market and long-term contracts in its Quarterly Electricity Report. It is too early to tell whether these data can yield good approximations to market prices in areas lacking formal markets. Outside of the ISOs official power flow data is of uneven quality. [16]

Excepting PJM and New York, official data cannot be used to show the extent or growth of economic trade. Outside of the Northern ISO's it is not possible to show wholesale prices differences are narrowing.

4. Filling the Information Gaps

Much of the data needed to evaluate the grid's support of markets is already being collected. EIA collects comprehensive data on generators, including those planning to connect to the grid. Those data are indispensable for analyzing the potential supply of electricity, generator entry to the market and for calculating market shares (see Chapter 6). The OASIS contains data critical to evaluating access, transmission tariffs and the quality of service (firm or nonfirm, point to point or network). NERC has data on power flows across the 230kv and above grid and on curtailments. The ISO's are reporting congestion.

OASIS and NERC data are either unusable, unavailable to government on a routine basis or both. The OASIS data is scattered across dozens of websites, are neither edited nor archived, and are not in useable form. NERC's power flow and curtailment data are not routinely available for government's monitoring of wholesale trade. Congestion data, trade flows and market price differentials are only available for the ISOs. Each defines and makes the data available (or not) differently.

[16] International import data illustrates some of the problems in estimated power flows across boundaries. Canada has long between an important supplier of low cost electricity to the United States. Most of the Canadian exports originate in Manitoba, Quebec, and British Columbia and are generated by hydroelectricity. How much has been supplied is a not clear. Data on international electricity trade with Canada (and Mexico) are available on an annual basis from the United States government (U.S. Department of Energy, DOE Form FE-781R, "Annual Report of International Electrical Export/Import Data."). An alternative source for Canadian transactions is available from the Canadian national government through the National Energy Board (NEB) The NEB collects information directly from market participants, many of whom trade power through long-term contracts making use of Presidential Permits.

The NEB generally reports greater volumes than DOE, in magnitudes too large to be explained by differences in metering.

Table 3-5a. Reported Electricity Transactions, NEB and DOE,

(billion	Imports (to		Exports (to		Net	
	U.S.	NEB	U.S.	NEB	U.S.	NEB
1997	7.83	43.06	15.56	7.47	32.37	35.59
1998	5.41	39.50	15.95	11.68	29.46	27.82
1999	38.56	42.91	12.28	12.95	26.28	29.96
2000	43.68	48.52	11.24	12.68	32.44	35.84
2001	31.12	38.40	12.36	16.10	18.77	22.30

Sources: US: United States Department of Energy, Form
Canada: National Energy Board.

Table 5-9. Modify Existing Data Collections

Information Needed	Form/Collection	Needed Changes	Comment
1. Access time series data by provider	OASIS	Consolidate, edit and archive all data required on OASIS in a single database	
2. Transmission Service Offerings and actual rates	OASIS	As above	
3. Cost and time required for generator connection	EIA 860	Report how much generator paid for grid reinforcements, direct (other) connection costs, and the date of the initial connection request	For newly activated generators, add questions to Schedule 3, Part B line 4
4. Load serving entity cost and quality of transmission service	EIA 861	Report percent of supply covered by long term contract, % covered by firm service (or FTR), transmission service expense and curtailments (MWh) of firm and non-firm service in last year	Schedule 2, Part B
5. Generator cost and quality of transmission service	EIA 906	Report paralleling that of Load serving entities, see above.	
6. Congestion costs, trade flows and price differentials	ISO Web sites	FERC and ISOs define data elements the same way across ISOs and report data to FERC.	None of this data is available for analyzing the effect of restructuring policy outside of the ISOs

Nationwide data on seams costs could only be obtained with a new survey. Cost and quality of transmission service could be obtained either by modifying the data utilities are required to report on OASIS or by adding questions to existing EIA forms.

Some of the data needed to monitor the grid's support of markets may become available in the course of meeting other needs. The government's ability to analyze the physical basis for load pockets and bottlenecks, and to determine what investments would mitigate

them are dependent on its having access to high quality power flow models. The government may decide to build and maintain such models for reliability or national security reasons and make them available for public policy analysis. If so, there is no need for additional models to study load pockets and bottlenecks.

FERC's recent Quarterly Electricity Report, intended in part to monitor trading, may permit reasonable estimates of wholesale prices in areas outside of ISOs and associated power flows. If not, a new collection would be necessary to allow valid comparisons of regional prices, their differences and associated power flows. Such a data collection would require significant research and development if the price and trade data were to be useful for economic analyses.