Self Regulating Markets for Electricity?

An Experimental Analysis of How Active Buyers can Help the NYISO and NYS

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by

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with

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Why Demand Responsiveness?

1. Get Customers into the Game
2. Mitigate Supplier Market Power
3. Efficient Use of Resources

   (Including the Environment)
4. Affect System Operation

Questions:

1. Why Has Utility Promotion been so Tepid?
2. Why Haven't Marketers Jumped In?
3. What Type of Demand-Side Market Structure
   a. Is the Most Efficient?
   b. Is Understood and Effectively Used by Consumers
   c. Might be Selected by Customers, Given a Choice?
4. Effect on Line Flow Predictability?

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Why Laboratory Experiments?

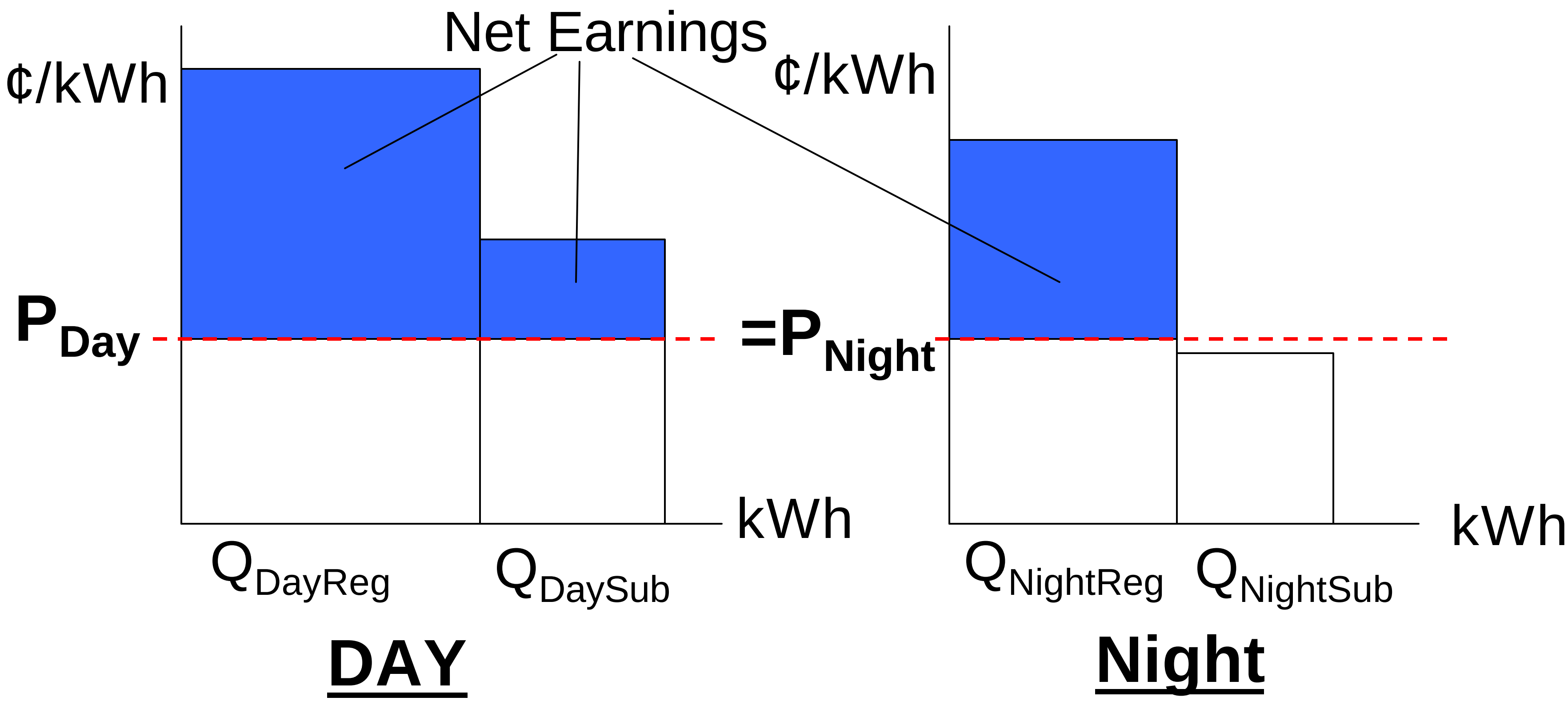
1. Theory Not Up to the Task
2. To Avoid Social Cost of
   Experiments of the Whole (e.g. California)
3. Low Cost Alternative for Winnowing
   Out Alternatives
4. Reveals Human Cognitive Processes
   (Learning & Lags)
5. Value as Educational Tool

But to be Effective,
_ _ _ Participants Must be Paid!

Demand-Side Behavioral Representation

1. **Start with Final Demand**: We Need to Understand Behavior of End-Use Customer Before We Represent Marketing Agents
2. Disaggregate **Observed Market Demand** Characteristics to Representative Individual Buyers
3. Develop “Induced Valuation” Relationships for Individuals
4. **Customer’s Problem**:
   Select Electricity Consumption in Each Period to Maximize Total Value – Total Expenditure
5. Compensate Subjects in Proportion to Net Benefits (as computed in 4)

Illustration of Buyer's Problem
(with Constant Price)



In this Example: $Q_{Day} = Q_{DayReg} + Q_{DaySub}$

$Q_{Night} = Q_{NightReg} + 0$

$Q_{DaySub} + Q_{NightSub} \leq Q_{SubMAX}$

Average Demand Curve

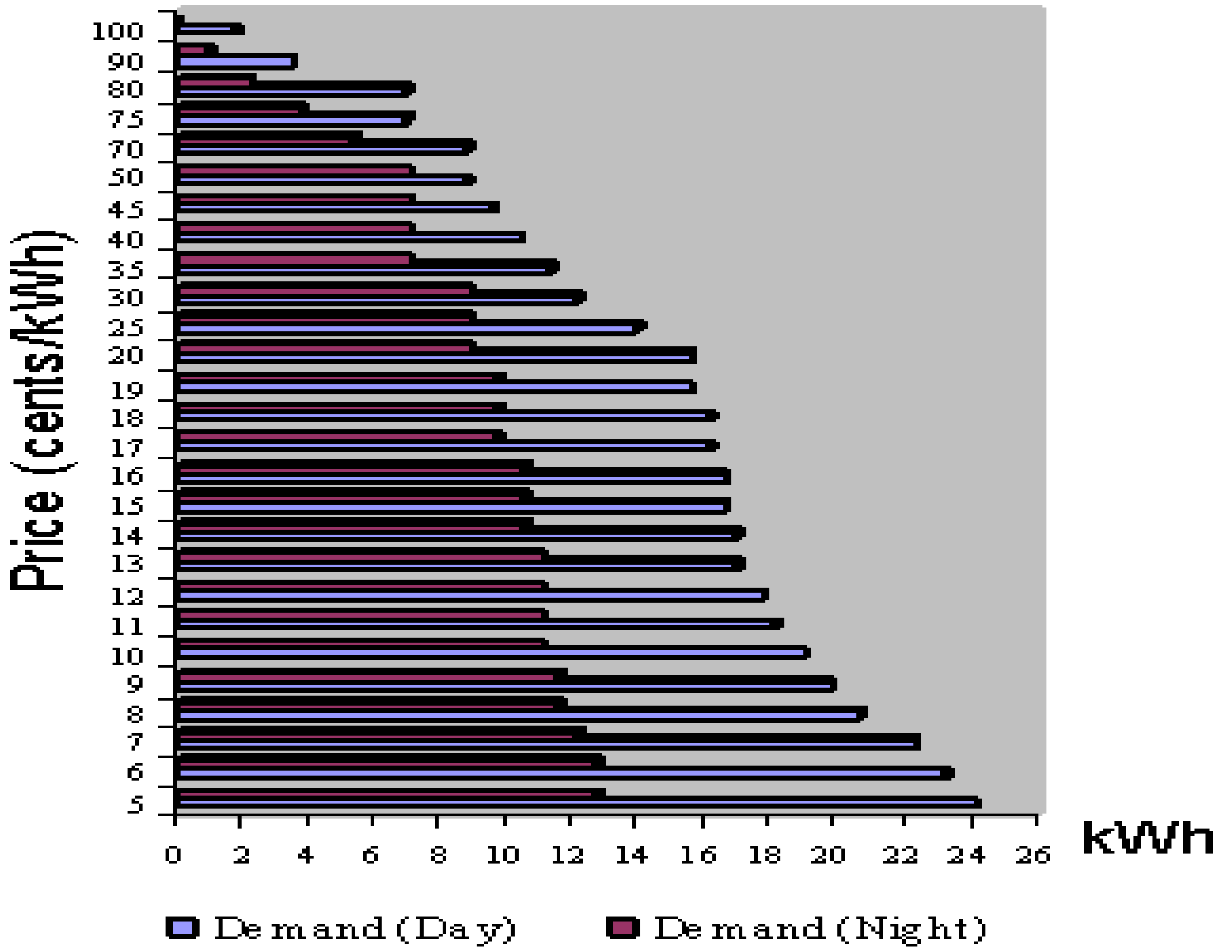
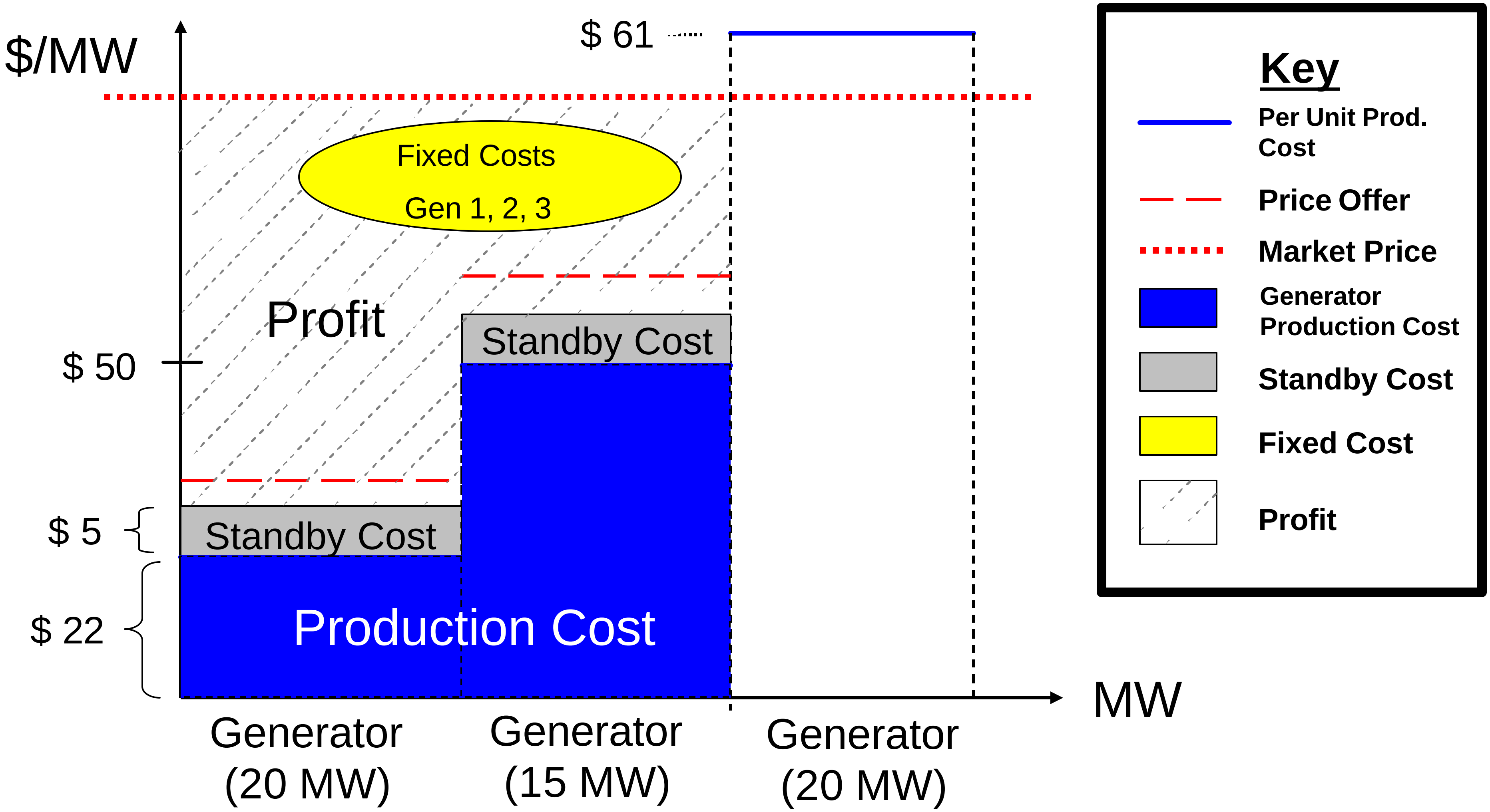


Illustration of Seller's Problem



Conceptual Framework for Efficient Market Structures

1. Reliability Provided through Networks Has Public Good Aspects:

   Market Cannot Solve Completely!

2. Efficient Customer Response Requires Both:
   - Real Time Pricing of Energy (**RTP**)
   - Demand Reduction Program (**DRP**) to Represent Cost Offset for Generation Reserves

Demand Side Scenarios

FP (Fixed Price) – Pre-announced, Constant Identical Prices in All Periods (the Baseline) – Quantity Bids

DRP (Demand Response Program) – FP with Preset Savings in Pre-announced Periods for Purchases Below Benchmark – Quantity Bids

RTP (Real Time Pricing) – Forecast Day/Night Prices – Quantity Bids – Customers Pay Actual Market Clearing Price

Note: RTP with buyers specifying a maximum price (limit orders) was piloted, but was no more effective

Experimental Design for Three Treatments over 11 Day/Night Pairs

Treatments: **FP** (Baseline); **DRP** (Specified/kWh Credit); **RTP** (Forecast Prices, Q-Bids, Pay Mkt. Price)

Characteristics of Day/Night Pairs:

1	2	3	4	5	6	7	8	9	10	11
N	S	H	N	N	N	H+S	H+S	N	S	H

N=Normal; H=Heat Wave; S=Random Supply Shortage

Preference Poll, "What Do You Prefer: DRP or RTP?"

After FP
After DRP
After RTP ➔ Determines Selection of Additional "High Stakes" Runs on Pairs 1 to 4

Two Separate Identical Trials Were Conducted – with Different Participants

Experiments Conducted

1. Single-Sided Market
   - 3 Active Demand Treatments
   - Predetermined Cost-Based, Hockey-Stick Shaped Offers with Random Outages
   - Two Repeats with 21 Professional Students, Total
   - May Reflect Active Demand Side in Market with Supplier Regulations (current NYISO markets)

2. Two-Sided Markets
   - 3 Active Demand Treatments
   - Active Suppliers without Regulations
   - Two Repeats, Each with 7 Suppliers (6 Experienced Grad. Students + 1 Agent) and 19 Buyers (Undergrad. & Grad. Students + Agents)

Details on Market Sequence

1. Load Forecasts (ISO) for Day/Night Pair + Announced Outages
2. Quantity-Price Offers (Suppliers)
3. Prices (ISO) for Day/Night Pair
   a. FP: Firm 8.5 ¢/kWh (includes 4 ¢/kWh Wires Charge)
   b. DRP: Firm 8.5 ¢/kWh + whether a 7.9 ¢/kWh DRP Credit Applies
   c. RTP: Day/Night Price Forecasts
4. Purchases (Buyers) for Day/Night Pair
5. Market Clears (ISO) at Last Accepted Offer or External Purchases, if Required

Details on Market Sequence (cont.)

6. Settlement (ISO)
   a. Buyers Pay:
      1. **FP**: 8.5 ¢/kWh
      2. **DRP**: 8.5 ¢/kWh – DRP credit if applies
      3. **RTP**: Market Clearing Price for Step 5.
   b. Sellers Receive:

      Market Clearing Price in All Cases – 4 ¢/kWh Wires Charge

7. Required Rate Change (ISO)

   after 11 Day/Night Pairs for FP and DRP

Buyer’s Computer Screen

Name: [test] Test User Logout
Session: [2] Example Session
Representing: [34] Buyer 1

Period
FP-1

SYSTEM DATA	Day	Night
Market Condition	Normal	Normal
Fixed Price (¢/kWh)	8.5¢	8.5¢

BUYER DATA	Day	Night
Regular Energy Value (¢/kWh)	15.0¢	13.0¢
Regular Max Energy Quantity (kWh)	7000	5000
Substitutable Energy Value (¢/kWh)	11.0¢	7.0¢
Substitutable Max Quantity (kWh)	2000	

MY BIDS	Day	Night
Energy Quantity Bid (kWh)	9000	5000
	Submit	
Regular (kWh)	7000	5000
Substitutable (kWh)	2000	0

EARNINGS	Day	Night
Benefits from Energy Consumption	$ 1270	$ 650
Cost of Energy Purchased	$ 765	$ 425
Energy Earnings	$ 505	$ 225

Gray background indicates computed values.

Seller's Computer Screen

POWER WEB

Name: [test] Test User Logout
Session: [2] Example Session1
Representing: [29] Seller 3

Period
FP-1

SYSTEM DATA	Day	Night
Market Condition	Normal	Normal
Forecast Load (MW)	196.0	118.0

GENERATOR DATA	Day			Night		
	Gen 7	Gen 8	Gen 9	Gen 7	Gen 8	Gen 9
Max Capacity (MW)	20.0	15.0	20.0	20.0	15.0	20.0
Per-Unit Production Cost ($/MW)	$22.00	$50.00	$61.00	$22.00	$50.00	$61.00
Standby Cost ($/MW)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Fixed Cost ($)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00

MY OFFERS	Day			Night		
	Gen 7	Gen 8	Gen 9	Gen 7	Gen 8	Gen 9
Capacity Offer (MW)	20	15		20	15	
Price Offer ($/MW)	22	100		22	100	

Note: Initial offers are set at your previous offer levels.

Submit

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CERTS

Experimental Results

1. Which Market Structure is **Most Efficient** (As % of Theoretical Maximum)?

	Active Demand/Preset Cost-Based Supply with Random Shift	**Full Two-Sided Market**
RTP	99.6%	99.4%
DRP	96.9%	98.7%
FP	98.7%	99.1%

2. What **Rate Change** is Required After Runs to Balance the Budget?

	Active Demand/Preset Cost-Based Supply with Random Shift	**Full Two-Sided Market**	
		First Exp.	**Second Exp.**
RTP		--	--
DRP	**N/A**	+ 2.1 ¢/kWh	+ 0.8 ¢/kWh
FP		+ 1.5 ¢/kWh	+ 1.5 ¢/kWh

Experimental Results:

Two-Sided Experiments: Details on Overall Efficiency for Combined Trials

1. Surplus Differences as % of FP Revenues without Regulation:

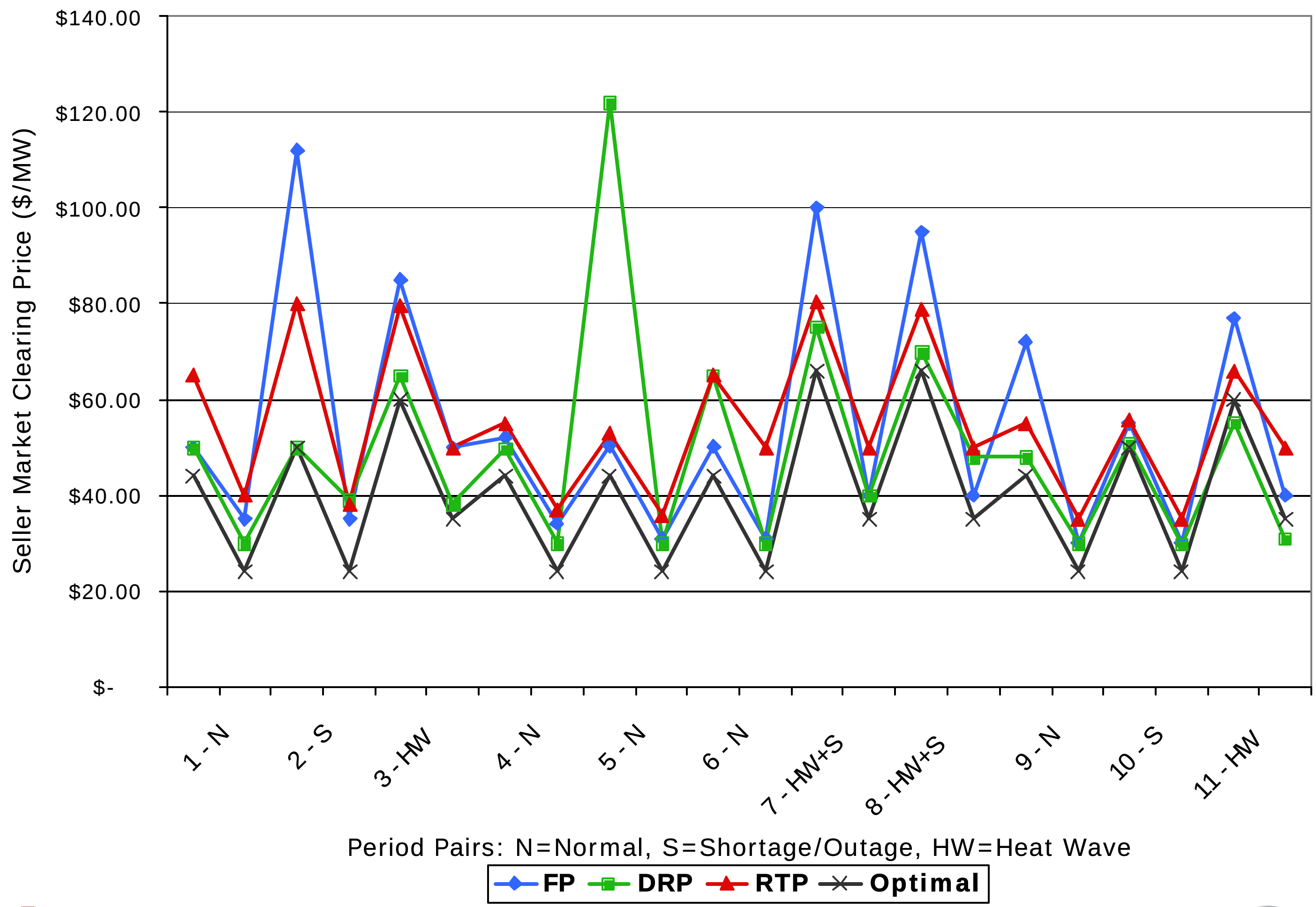
	% Added Consumer Value	% Changes Supplier Profit	Combined Change
RTP	9.02	-6.99	2.02%
DRP	13.86	-17.52	-3.67%
Social Optimum (as comparison)	29.32	-22.57	6.75%

2. Statistically Valid Differences in Behavior from FP Results (@ .95 level):

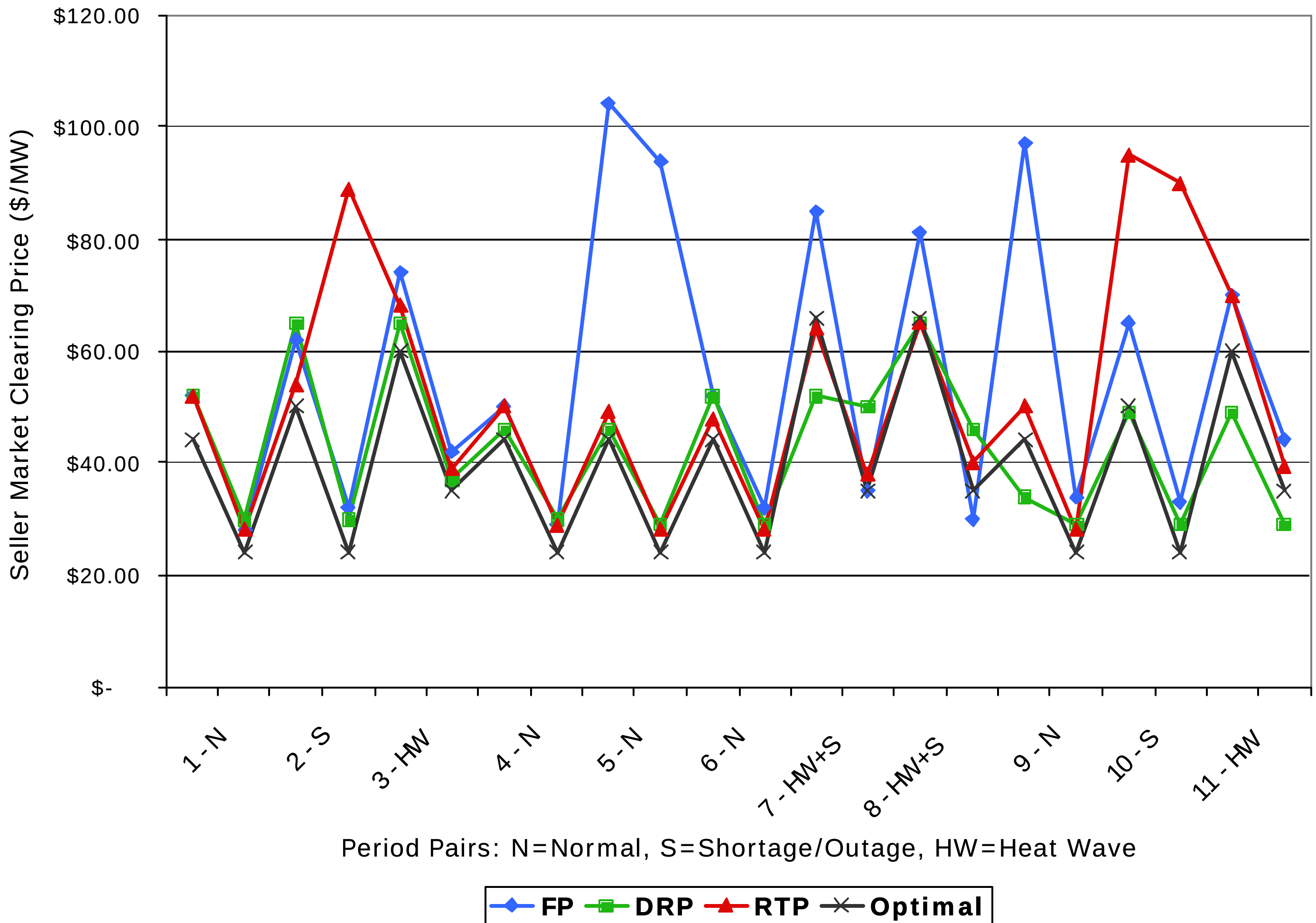
	RTP vs. FP		DRP vs. FP	
	Consumers	Sellers*	Consumers	Sellers*
Value/Profit	+	—	+ ?	—
Quantities Bought/Sold:				
Days	—	— ?	—	—
Nights	+	+ ?	—	+ ?

*Note: With fewer sellers, statistical significance is harder to attain.

Prices: Two-Sided Market (Group 1)



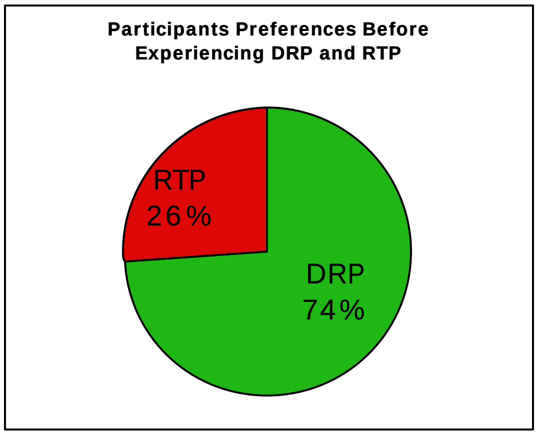
Prices: Two-Sided Market (Group 2)



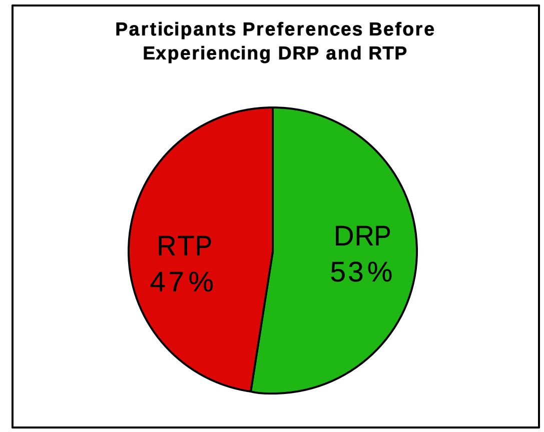
Experimental Results: Participant Preferences in Two-Sided Markets

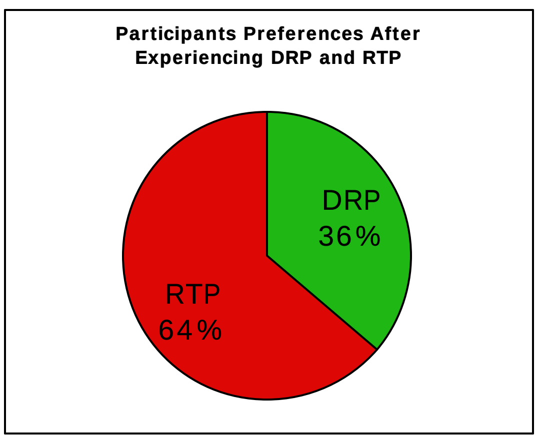
Experiment 1:

Experiment 2:

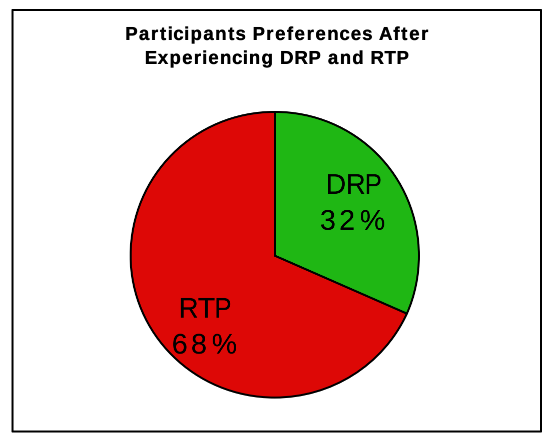


Before

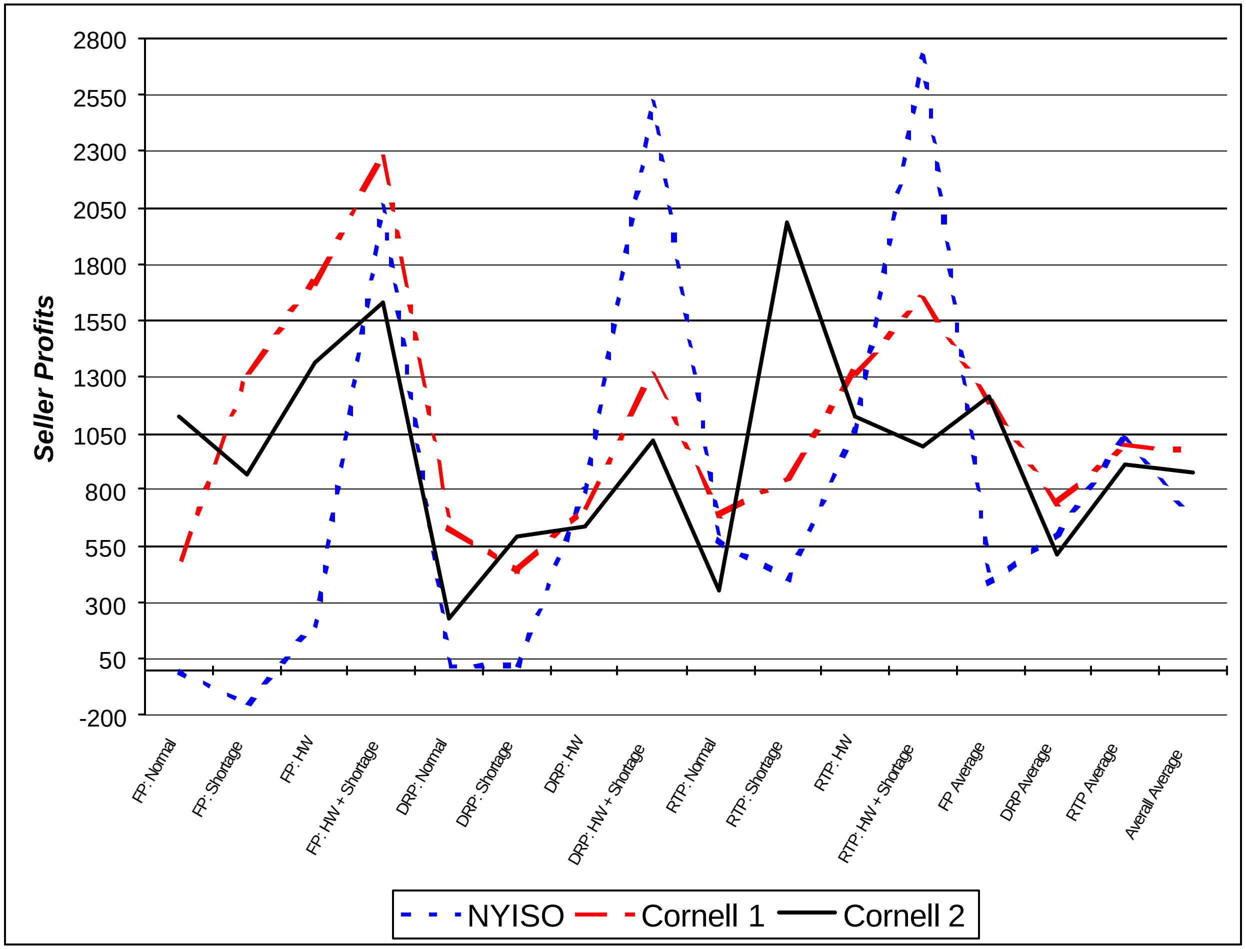




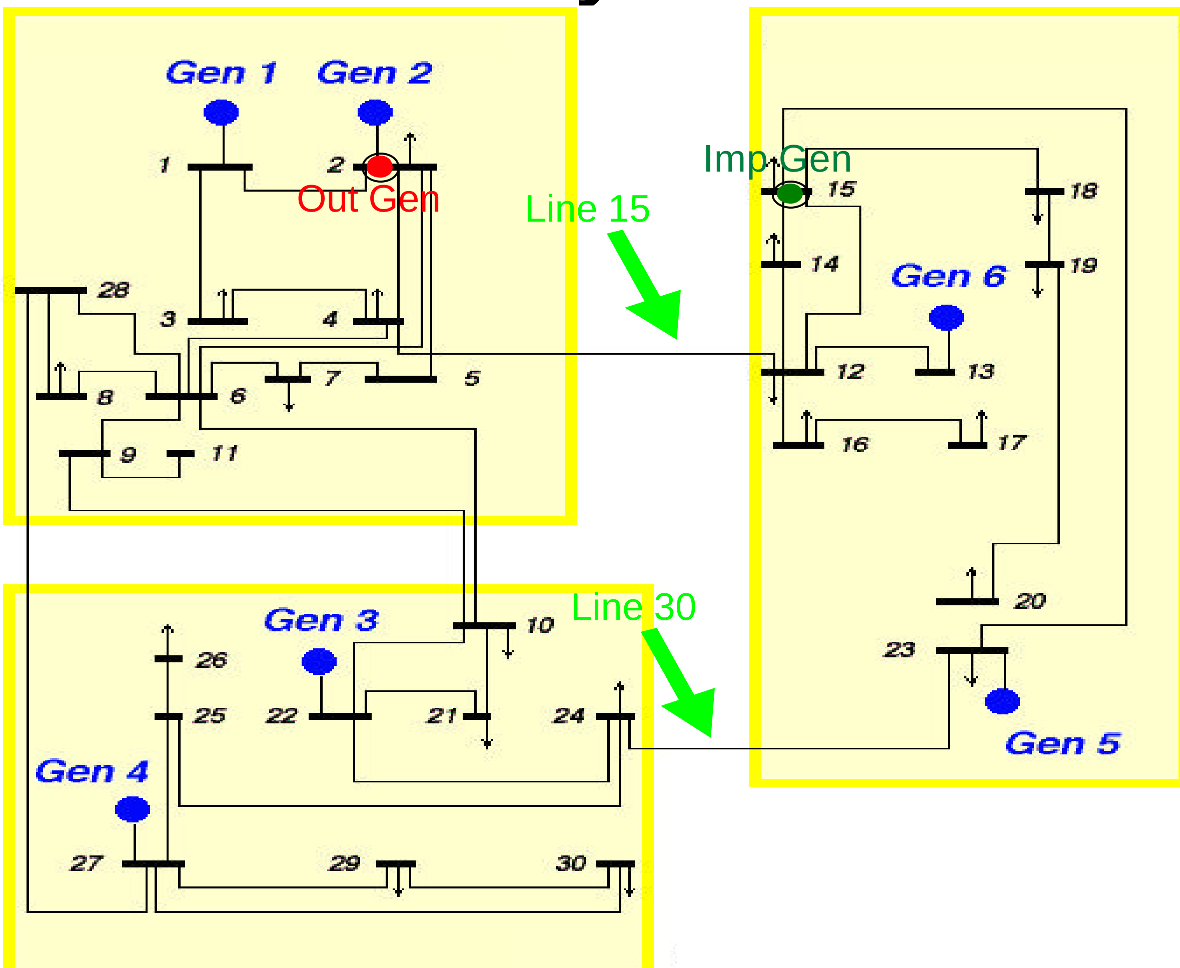
After



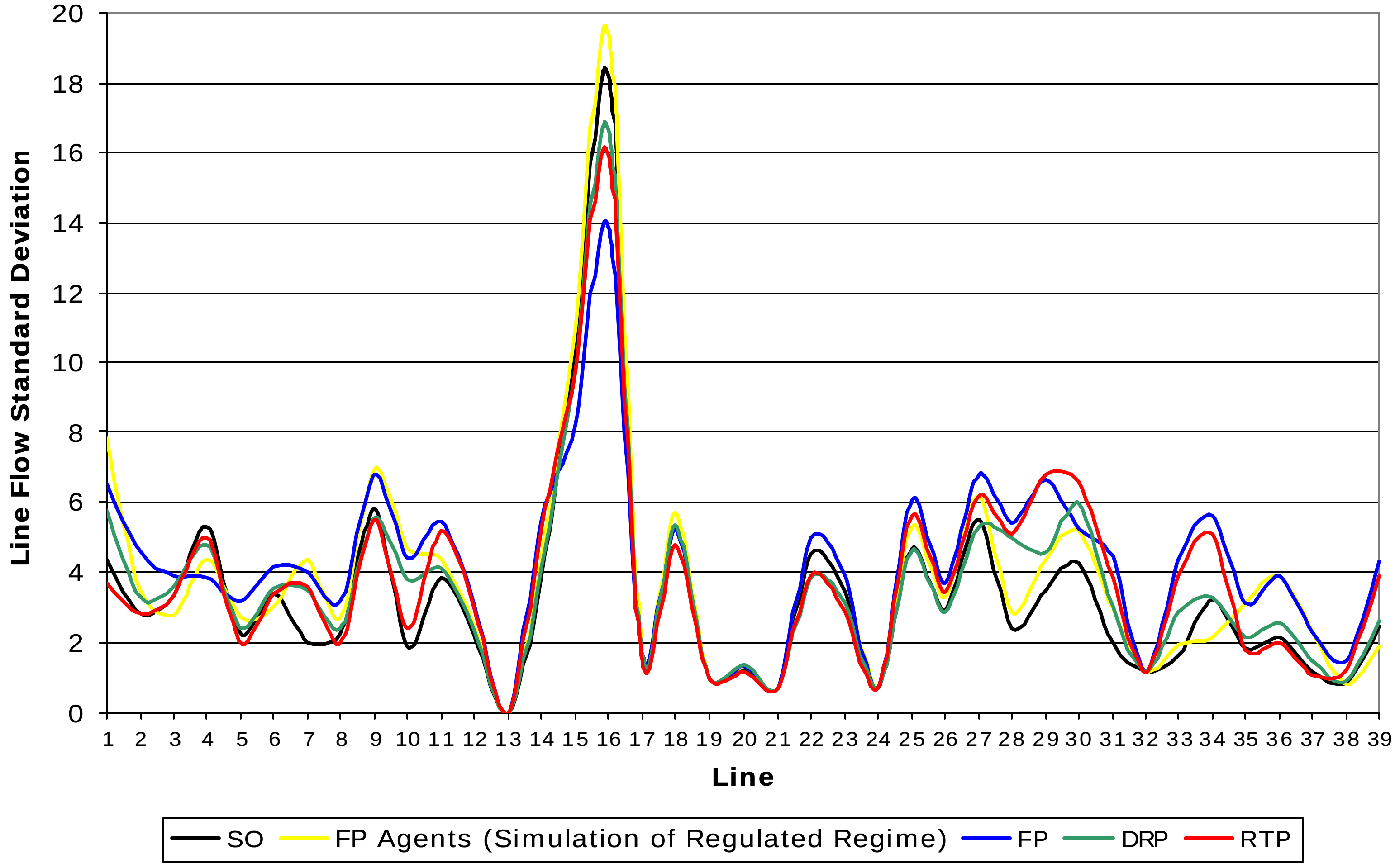
Comparison of Experts and Students as Participants in Two-Sided Experiments (Average Seller Earnings)



Schematic of Underlying Electricity Network



Standard Deviation in Line Flows



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Relationship Between Line Flows and System Load

	Social Optimum	(Reg. Regime) Fixed Price with Regulated Sellers	*Results with Active Participants* Fixed Price	Demand Reduction Program	Real Time Pricing
Regression Results for Tie Line 15					
Intercept	40.1779	39.1761	17.9780	29.9462	33.0568
Std Err	3.0375	2.1514	3.1385	3.8662	3.5013
Slope Coefficient	(0.1982)	(0.1901)	(0.1025)	(0.1789)	(0.1909)
Std Err	0.0167	0.0116	0.0168	0.0236	0.0197
R-Squared	0.7701	0.8657	0.4695	0.5777	0.6906
F-Statistic	140.6651	270.7614	37.1714	57.4517	93.7394
P-value	0.0000	0.0000	0.0000	0.0000	0.0000
Regression Results for Tie Line 30					
Intercept	(17.5262)	(18.5527)	(9.1573)	(13.9666)	(17.5818)
Std Err	1.5631	1.7259	2.4566	3.0202	3.1587
Slope Coefficient	0.0751	0.0753	0.0437	0.0802	0.1024
Std Err	0.0086	0.0093	0.0132	0.0184	0.0178
R-Squared	0.6449	0.6111	0.2079	0.3104	0.4409
F-Statistic	76.2617	66.0048	11.0260	18.9069	33.1193
P-value	0.0000	0.0000	0.0019	0.0001	0.0000

Note: The following linear regression equation was estimated with OLS.
Line Power Flow = Bo + B1 x System Load
N = 44 for all regressions

Results (and Their Significance)

1. Customers Can Perform Efficiently in Electricity Markets,if Given the Chance
2. Markets Perform More Efficiently with Customer Participation, with Less Need for Market Power Mitigation
3. Real Time Pricing Perform Better that Pre-announced Demand Response Programs in Most Cases
4. Customers Prefer DRP before Trying RTP, but Switch Their Preferences after Experiencing RTP
5. Line Flows May be More Predictable with Demand Response