An International Comparison of Models for Measuring Market Power in Electricity

James Bushnell
Christopher Day
Max Duckworth
Richard Green
Arve Halseth
E. Grant Read
J. Scott Rogers
Aleksandr Rudkevich
Tristram Scott
Yves Smeers
Hillard Huntington

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This paper summarizes in tabular format eight existing models for measuring market power in electricity. The models focus on California, New England, England and Wales, Norway, Ontario, and New Zealand (2).

We hope to expand the coverage to other models as they become available.

The key model proprietors (who responded to the EMF questionnaire) and available papers are:

James Bushnell (in conjunction with Severin Borenstein), University of California Energy Institute, Berkeley, CA.

> Severin Borenstein and James Bushnell, "An Empirical Analysis of the Potential for Market Power in California's Electricity Industry," University of California Energy Institute, Berkeley CA.

Christopher J. Day (in conjunction with Derek W. Bunn) Decision Science Department, London Business School, London, England.

> Christopher J. Day and Derek W. Bunn, "Agent-based Simulation of Electric Power Pools," London Business School, London, England.

Richard Green (in conjunction with David Newbery), Department of Applied Economics, University of Cambridge, England.

> Richard Green and David Newbery, "Competition in the British Electricity Spot Market,""Journal of Political Economy, 1992, 100(5): 929-953.
>
> Richard Green, "Increasing Competition in the British Electricity Spot Market," Journal of Industrial Economics , 1996, 44(2): 205-216.

Arve Halseth, ECON, Center for Economic Analysis, Oslo, Norway.

> Arve Halseth, "Market Power in the Nordic Electricity Market," ECON, Center for Economic Analysis, Oslo, Norway.

E. Grant Read, Department of Management, University of Canterbury, Christchurch, New Zealand.

> E. Grant Read, U. of Canterbury, and John Culy, NZ Institute of Economic Research, "Short Term Gaming Model"

Tristram Scott, Caminus Energy, Cambridge, UK, formerly with Department of Management, University of Canterbury, Christchurch, New Zealand.

J. Scott Rogers, Department of Industrial Engineering, University of Toronto, Canada
GENeration COMPetition (GENCOMP) Model Version 2.0 as presented at Institute for Operations Research and Management Science (INFORMS) Meeting, Seattle, Nov 1998

Aleksandr Rudkevich (Tabors, Caramanis & Associates) and Max Duckworth (Constellation Power Source, Baltimore, MD, USA), both formerly with Tellus Institute, Boston, MA, USA
Aleksandr Rudkevich, Max Duckworth and Richard Rosen, 1998, "Modeling Electricity Pricing in a Deregulated Generation Industry: Potential for Oligopoly Pricing in a Poolco." Energy Journal, Vol. 19, No. 3, p. 19-48

Aleksandr Rudkevich and Max Duckworth, 1998, "Strategic Bidding in a Deregulated Generation Market: Implications for Electricity Prices, Asset Valuation and Regulatory Response." Electricity Journal, Vol. 11, No.1, p. 73-83

Testimony of Aleksandr Rudkevich before the New Hampshire Public Utilities Commission in Docket No. DE97-251, March 11, 1998

Yves Smeers, CORE, Université Catholique de Louvain, Belgium (in conjunction with Jacqueline Boucher and Olivier Daxhelet, Electrabel, Belgium)

Table 1: Model Overview

Model Characteristic	James Bushnell, UC Berkeley	Richard Green and David Newbery, U. of Cambridge	Arve Halseth, ECON Norway
Region(s)	WSCC (Western US). California is treated in detail, other western states are grouped into two "fringe" supply regions, Pacific NW (w/Canada) and Desert Southwest.	England and Wales	The Nordic region: Norway, Sweden, Denmark and Finland
Time Horizon	24 individual hours, 6 each from March, June, September, Dec. of 2001	Calibrated for 90 -94	12 month period
Reporting Frequency	Key hours in a single year	Single year	Monthly by 3 typical load situations
Original Purpose	General overview of the California market, identify trouble periods and key sensitivities	Estimate extent of market power	Simulation of the market balance and power prices.

Table 1: Model Overview (Continued)

Model Characteristic	J. Scott Rogers, U of Toronto Model Name: GENCOMP 2.0*	E. Grant Read , U. of Canterbury, and John Culy, NZ Institute of Economic Research, "Short Term Gaming Model"	Tristram Scott and E. Grant Read, U. of Canterbury
Region(s)	One	One	The model has been applied to, but is not restricted to the New Zealand system.
Time Horizon	One	Week	20 years, no particular start or end date
Reporting Frequency	Annual	LDC Class	Weekly
Original Purpose	To analyze the effects of different assumptions about competition among generators on amounts supplied and prices	To study spot market gaming in NZ and Victoria (Australia)	Reservoir management model for a competitive environment. Built for PhD thesis.

Table 1: Model Overview (Continued)

Model Characteristic	Christopher Day and Derek W. Bunn, London Business School	Alex Rudkevich (Tabors Caramanis) and Max Duckworth (Constellation Power Source)	Jacqueline Boucher and Olivier Daxhelet, Electrabel, and Yves Smeers, CORE, Université Catholique de Louvain
Region(s)	England and Wales	Can be adapted to any poolco market (i.e., bid-based power pool); has been applied to NEPOOL, northern Maine, Pennsylvania and Nevada	Can be adapted to any region. Data are currently collected for the EU region.
Time Horizon	Three "typical" demand days (summer, autumn-spring and winter) for one year	One year, divided into up to ten segments representing days in the year with similar load shapes (i.e., similar peak daily loads and intra-day loads.)	One year, divided into an arbitrary number of time segments, each represented by a single demand curve.
Reporting Frequency	Half hourly for the day in question	Each hour of each load segment, total for a load segment, plus annual aggregation	Each time segment, according to the time decomposition of the year.
Original Purpose	To understand the dynamic interaction of generating companies in the England and Wales pool.	Estimate potential for strategic bidding (SFE-based bidding and/or capacity withholding) in any day-ahead poolco market	Assess the competitive position of companies in a bilateral market, with market power and regulated transmission.

Table 2: Model Scope

Model Characteristic	James Bushnell, UC Berkeley	Richard Green and David Newbery, U. of Cambridge	Arve Halseth, ECON Norway
Represented Participants	1. Generators – Utilities, US hydro projects, QFs 2. A grid company - implicit 1. Power marketers/suppliers – assumed trades are efficient - implicit 2. Distribution companies – regulated	1. Generators – National Power; Power Gen; all others 2. Consumers – demand curve	1. The five largest generators and a competitive fringe 2. Consumers: residential, energy intensive industry, other industry and services.
Functions	Cost and demand curves	Cost and demand curves	1. Generators: cost curve with capacity constraints 2. Consumers: Price elasticities around -0.5.
Spatial Representation	Spatial "pipeline" representation of interstate transmission constraints	Single node	Spatial

Table 2: Model Scope (continued)

Model Characteristic	J. Scott Rogers, U of Toronto Model Name: GENCOMP 2.0*	E. Grant Read, U. of Canterbury, and John Culy, NZ Institute of Economic Research, "Short Term Gaming Model"	Tristram Scott and E. Grant Read, U. of Canterbury
Represented Participants	1. Generators - many different types of units and owners 2. A grid company - Central Market Operator 3. Consumers – several customer classes	1. Generators 2. Consumers	1. Generators: Duopoly. 2. Consumers: Single Entity
Functions	1. Generators - characterized by ownership of units each of which has a fixed operating cost, a variable cost, an availability and a fixed annual operating cost 2. Grid company- CMO 3. Consumers: Each class represented by a different sensitivity to prices at different times	1. Generators: Step function supply curve + contracts. 2. Consumers: Demand curve.	1. Generators: Marginal cost/capacity/ contracts 2. Consumers: Constant elasticity or linear demand curve.
Spatial Representation	Single node	Single node	Single node.

Table 2: Model Scope (continued)

Model Characteristic	Christopher Day and Derek W. Bunn, London Business School	Alex Rudkevich (Tabors Caramanis) and Max Duckworth (Constellation Power Source)	Jacqueline Boucher and Olivier Daxhelet, Electrabel, and Yves Smeers, CORE, Université Catholique de Louvain
Represented Participants	1. Generators – National Power; PowerGen, Eastern Group. All others as price-taking fringe. 2. Consumers – demand curve	1. Generators 2. Import/export contracts 3. Load	1. Generators / Power Marketers 2. Transmission company (at this stage one System Operator) 3. Consumers
Functions	Marginal Cost and demand curves	Cost curves (production cost curves) and linear demand response function	1. Generators are represented by cost, capacity and efficiency characteristics 2. The network is represented by a DC load flow approximation 3. Demand is described by linear demand curves
Spatial Representation	Single node	Single node for generation and load, with capability to model one transmission constraint between generation and load (load pocket)	An electrical grid

Table 3: Assumptions

Model Characteristic	James Bushnell, UC Berkeley	Richard Green and David Newbery U. of Cambridge	Arve Halseth, ECON Norway
Supply behavior	1. Cal Investor Owned Utilities – chooses quantities 2. Munis, non-Cal IOU's, US water projects – price takers 3. QFs, Cal IOU nukes – "must-run units that do not receive market price	1. Generators – supply curve for National Power & PowerGen 2. New entrants – price takers	1. Generators: choose both prices and quantities 2. Grid company: Regulated 3. Power marketers/suppliers: price taker 4. Distribution company: regulated 5. Consumers: price taker
Agents exerting market power	Nested equilibrium: Cournot equilibrium with competitive fringe	Supply curve equilibrium	Supply curve equilibrium
Multi-stage or sequential decisions	None	Entry (in '94 version); supply function competition (in later versions).	None
Agents subject to price regulation	Regulated generators are treated as price-takers	None	Transmission and distribution: Average cost
Producer supply curves	Step functions	Continuous curves	Horizontal-step functions
Long-run price elasticity of demand	Aggregate demand elasticity tested for -0.1, -0.4, and -1.0	Elasticity of –0.5 used as benchmark	Residential –0.8 Services and other industry: -0.4 Energy intensive industry have exogenous demand

Table 3: Assumptions (continued)

Model Characteristic	J. Scott Rogers, U of Toronto Model Name: GENCOMP 2.0	E. Grant Read, U. of Canterbury, and John Culy, NZ Institute of Economic Research, "Short Term Gaming Model"	Tristram Scott and E. Grant Read, U. of Canterbury
Supply behavior	Generators- choose price and quantities to maximize profits Grid company- chooses quantities and pays marginal cost to minimize payments to generator firms Consumers- demand curve by customer class	Generators: unregulated, choosing P, Q, or both. Consumers: price takers.	Generators: either Cournot oligopolist or price taker or fixed output. Consumers: demand curve.
Agents exerting market power	Nash equilibrium – generator firms are profit maximizing entities with expectations about competitors' behaviour	Cournot game (but with limited search strategies).	No co-operative behaviour, although agents can trade one way (back-up) contracts. Cournot equilibrium either without or with competitive fringe. In both cases there is a non-competitive (fixed output) fringe.
Multi-stage or sequential decisions	None	None	Contracts are set as input parameters. Reservoir release is optimised over time via dual dynamic programming.
Agents subject to price regulation	CMO-- Marginal cost (short run or long run)	Restrictions can be placed to force prices and/or quantities to be consistent over all periods in a week.	None
Producer supply curves	Not applicable	Horizontal-step functions	Horizontal step functions, although continuous curves could be implemented.
Long-run price elasticity of demand	Elasticity is a specified value about a current price-quantity pair	Only short run elasticities modelled.	Tested with elasticities of -0.1 to -0.8.

Table 3: Assumptions (continued)

Model Characteristic	Christopher Day and Derek W. Bunn, London Business School	Alex Rudkevich (Tabors Caramanis) and Max Duckworth (Constellation Power Source)	Jacqueline Boucher and Olivier Daxhelet, Electrabel, and Yves Smeers, CORE, Université Catholique de Louvain
Supply behavior	1. Generators – supply curve for National Power, PowerGen and Eastern Group 2. New entrants, interconnectors and Nuclear – price takers	1. Gencos can be modeled as engaged in strategic behavior (SFE-based bidding and/or capacity withholding) or as price-takers 2. Imports/exports/QFs are "must-run"	Generators / Power Marketers behave in perfectly competitive way or *à la* Cournot on each consumer market Some fraction of the market (the *non-eligible* market in EU language) is price cap regulated
Agents exerting market power	Agents hold supply function conjectures about opponents and optimise given these beliefs - no pure or mixed strategy equilibrium is calculated. Bertrand-Edgeworth type outcomes can be observed.	SFE-based bidding and/or capacity withholding	Generators / Power Marketers can behave *à la* Counrot, modified by some conjectural variation.
Multi-stage or sequential decisions	None	Capability to model (non-dynamic) new entry	None
Agents subject to price regulation	None	Regulated generators can be modeled as price takers and/or as owners of "must-run" units	- the System Operator when pricing transmission services - the generators in the non-eligible (regulated market)
Producer supply curves	Piece-wise linear	Step functions	Not applicable (the equilibrium is not a supply curve equilibrium)
Long-run price elasticity of demand	Maximum elasticity of -0.3	<u>Short-run</u> elasticity of demand. User-defined value; have used wholesale price elasticities of –0.05, -0.1, and –0.5 → retail price elasticities of roughly –0.125, -0.25, and –1.25. Price elasticity is assumed at equilibrium in peak hour of each load segment. It is used to calculate the slope of the linear price function for each hour of each load segment.	<u>Short-run</u> elasticity is specified by the user at some reference point in each time segment.

Table 4: Structure

Model Characteristic	James Bushnell, UC Berkeley	Richard Green and David Newbery, U. of Cambridge	Arve Halseth, ECON Norway
Short-run elements	Short-run model, no investment	Incumbent capacity, entrant capacity	All elements are short run
Time segments for demand	Yes, see above	Yes, 3 typical days of half-hourly periods	Yes. The annual demand is decomposed into monthly consumption and 3 typical (monthly) load situations
Facilities	Supply side – thermal plant, hydro, nuclear, QF Demand side, constant elasticity demand curve, interruptible not explicitly modeled.	Supply side – all power stations. Demand side	Supply side - 'representative' power stations (cost classes) Demand side - constant elasticity demand curve
Quantity-limited generators	Yes, see above. Hydro energy was scheduled across periods by taking monthly energy production and "peak-shaving" the load duration curve with it.	Nuclear	Hydro producers
Single or multiple periods	Single period	Single year	Single year
Agent foresight	Myopic	N/A	Forward looking

Table 4: Structure (continued)

Model Characteristic	J. Scott Rogers, U of Toronto Model Name: GENCOMP 2.0*	E. Grant Read, U. of Canterbury, and John Culy, NZ Institute of Economic Research, "Short Term Gaming Model"	Tristram Scott and E. Grant Read, U. of Canterbury
Short-run elements	All short run (i.e. annual)	All short run, including contracts.	All are short run except for reservoir release decisions.
Time segments for demand	Load Duration curve	Yes	Yes. Weekly demand, broken down into a load duration curve of (typically) five sub-periods. Demand differs from week to week throughout the year.
Facilities	Supply side - unit types by generator firm Demand side- nothing explicit	Supply side: merit order of plants Demand side: nothing explicit.	Supply side: Firm one is Cournot, with hydro reservoir management (see below). Firm two is Cournot or price taker. No reservoirs. Also there is the non-competitive fringe of fixed output. Demand side: None, just demand curve.
Quantity-limited generators	Hydro is both run-of-river and pondage	No	Both firms have run of river (fixed release). Firm one has hydro with major storage. Inflow is stochastic.
Single or multiple periods	Single year	Single year	Either single year or multiperiod. Reporting is weekly, but also aggregated on an annual basis. Simulation can be either single year repeated with different infows, or several years end on end.
Agent foresight	Each has a strategic perspective on its ability to affect the market	Myopic	Only reservoir release is forward looking. Things like the effect of today's spot price on next week's contracts is not forward looking.

Table 4: Structure (continued)

Model Characteristic	Christopher Day and Derek W. Bunn, London Business School	Alex Rudkevich (Tabors Caramanis) and Max Duckworth (Constellation Power Source)	Jacqueline Boucher and Olivier Daxhelet, Electrabel, and Yves Smeers, CORE, Université Catholique de Louvain
Short-run elements	Supply function competition - no capacity withholding	Short-run model, no investment. Entrant capacity can be modeled on a scenario basis	All elements are short-run. No investments.
Time segments for demand	Half-hourly	Market clears hourly in each day for each load segment. Up to ten load segments.	Markets clear in each time segment. They also clear through the year when there is hydro.
Facilities	Supply side - merit order of plants Demand side - demand function	Supply side – all dispatchable and must-run generating units, plus import/export power Demand side – linear demand functions of price for each hour of each load segment.	- Supply side : dispatchable and non-dispatchable plants. Local (not transportable) demand and supply of reactive power - Demand side : linear demand curve in each time segment
Quantity-limited generators	No	All dispatchable and "must-run" generation derated by seasonal outage rates accounting for forced and planned outages	Hydro power plants
Single or multiple periods	Simulated repetition of the same demand day.	Single period (e.g., year)	Single period (e.g., year)
Agent foresight	Myopic	Gencos have perfect information about competitors' production cost curves, and can forecast next day peak load to within user-defined accuracy	Perfect information

Table 5: Solution procedure

James Bushnell, UC Berkeley	Sequential grid search, each player searches all output levels and sets output and profit maximizing level, sequence is repeated until no player changes its output.
Richard Green and David Newbery, U. of Cambridge	Numerical integration for supply function; then period-by-period calculation of (independent) demand-supply intersections for p and q. Entrant capacity adjusted until average price = entrant cost (supply functions did not depend on this capacity, so a simple demand shift was adequate to represent baseboard entry).
Arve Halseth, ECON Norway	1) For a given set of supply functions, GAMS/Minos is used to find the market equilibrium. 2) The equilibrium supply functions are found iteratively by evaluating for each producer if it's profitable to change the curve (upward or downward), given the supply functions from the rest of the producer's. An equilibrium is found if this procedure converge.
J. Scott Rogers, U of Toronto	PIES type solution among a sequence of quadratic programming models with a linear programming master problem.
E. Grant Read, U. of Canterbury, and John Culy, NZ Institute of Economic Research, "Short Term Gaming Model"	Heuristic gaming strategies including analytical resolution of some repeated gaming situations. Generators challenge the next generator, or the next above it, "Contest the margin" etc. This is implemented by iteration in a spreadsheet.
Tristram Scott and E. Grant Read, U. of Canterbury	We solve the spot market model (cournot duopoly, contracts, constant elasticity or linear demand) for a range of possible marginal water values, noting hydro release at each MWV. (And for each sub-period of LDC). This gives a Demand Curve for Release (DCR). We create a DCR for each period (week), either explicitly, or by interpolation from sampled periods (e.g. winter, spring, summer, autumn). The DCR's are combined using Dual Stochastic Dynamic Programming to give a marginal water value surface (WVS) for the time horizon. (Stochastic part is the expected inflows.) The WVS provides operating rules for the hydro station. Next we run the simulation model, using the WVS to provide optimal operating rules. Simulation is typically twenty years, either end on end or in parallel. Stochastic element in simulation is the actual inflows in each week.
Christopher Day and Derek W. Bunn, London Business School	Each generating company is modelled fully or partially optimising (numerically) its supply function as a best response to its beliefs about its opponents. This procedure is repeated, for the same day of demand. Day to day dynamics are observed and aggregate behaviour is analysed.

Table 5: Solution procedure (continued)

Alex Rudkevich (Tabors Caramanis) and Max Duckworth (Constellation Power Source)	Numerical integration of the one-dimensional Klemperer-Meyer equation used to calculate genco supply functions. (The KM equation represents competition between identical firms in the market, therefore a proxy approach is used to apply solution to non-symmetric market shares of gencos.) In capacity withholding case, a heuristic algorithm is adopted to find Nash Equilibrium Withholding Sets (NEWS). NEWS are considered in the context of a two-staged game. Stage 1 -- identify the set of units committed for the day, Stage 2 -- determine bid prices for committed units. Automatic demand response to price, and simultaneous balance of supply and demand.
Jacqueline Boucher and Olivier Daxhelet, Electrabel, and Yves Smeers, CORE, Université Catholique de Louvain	Variational ineaquality problem solved by optimisation techniques.