Public Policy and Economic Efficiency in Ontario's Electricity Market: 2002 to 2011

by
Derek E. H. Olmstead

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Abstract

A competitive wholesale electricity market began operation in Ontario in 2002. The institutional features and development process are described, and the outcomes associated with certain features are assessed.

First, a six-equation model of the market is specified and estimated. The results are used to undertake analysis of the province's renewable energy program. The impacts of the program on consumers' and producers' surplus, as well as the resulting degree of carbon dioxide (CO₂) emission-abatement, are estimated. These results are used to infer the per-unit cost of CO₂ abatement resulting from the program. Under the assumption that the renewable-fuelled energy displaces coal-fuelled energy from the market, the estimated cost is approximately \$93/tonne of CO₂; under the alternative assumption that natural gas-fuelled generation is displaced, the estimated cost is \$207/tonne of CO₂. Comparison to costs observed in other markets and jurisdictions reveals the program to cost approximately one order of magnitude greater than elsewhere. It is concluded that Ontario pays substantially more for emission abatement than is necessary or, alternatively, that Ontario achieves substantially less abatement than is feasible for each dollar of economic resources expended.

Second, the market model is also used to assess the treatment of electricity exports with respect to the so-called global adjustment charge. The analysis reveals that the current practise of exempting exports from the charge is not socially optimal from a total surplus-maximisation standpoint. That objective would be achieved if global adjustment was allocated to exports at approximately 32% of the rate at which it is applied to Ontario-based consumers, a result consistent with a Ramsey-type inverse elasticity rule.

Third, the forward market unbiasedness hypothesis is assessed in the context of the market for financial transmission rights (FTR). Issues related to left-censoring of payouts at \$0 and overlapping observations are dealt with. The analysis reveals little evidence in favour of the hypothesis, but finds less biasedness in long-term rights as compared to short-term rights. Analysis of bidder behaviour reveals greater levels of participation in auctions of FTRs that link Ontario to similarly competitive neighbouring jurisdictions as opposed to non-competitive jurisdictions.

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All errors and inadequacies that remain in this work are my own.

Table of Contents

Abstract	ii
Acknowledgements	iv
Table of Contents	v
List of Tables.....	xii
List of Figures	xxi
List of Appendices	xxiv
Chapter I: Introduction and purpose	1
Chapter II: A model of the market.....	3
1. Introduction and purpose	3
2. Methodology	11
2.1. Step one: the base case	11
2.2. Step two: the counterfactuals.....	12
3. The model: the role of the regulator and the wholesale market.....	12
3.1. The role of the regulator	12
3.2. The wholesale market	14
3.2.1. Supply.....	14
3.2.2. Demand	21
3.2.3. The regulator's budget constraint	25
3.2.4. Equilibrium	28
4. Data and literature review	29
4.1. Data.....	29
4.2. Previous estimates of price elasticities	33
5. Estimation and results	35
5.1. Estimation technique and estimates.....	36
5.2. Discussion	37
5.3. Price elasticity estimates.....	42

6. Fitted base case	43
6.1. Procedure	44
6.2. Base case results	56
7. Conclusions	59
 Chapter III: Impact of renewable energy generation.....	61
1. Introduction	61
2. Importance of issue and motivation of analytical approach.....	62
2.1. Importance of issue.....	62
2.2. Motivation of analytical approach.....	67
3. Analytical approach and anticipated effects.....	72
3.1. Counterfactual equilibrium	72
3.2. Change of total surplus.....	76
3.3. Change of CO ₂ emissions	83
3.4. Cost of CO ₂ emission abatement.....	85
4. Empirical results	85
4.1. Counterfactual equilibrium	85
4.2. Change of total surplus.....	91
4.3. Change of CO ₂ emissions	96
4.4. Cost of CO ₂ emission abatement.....	99
4.5. Bootstrapping the cost of CO ₂ emission-abatement.....	102
5. Discussion.....	105
 Chapter IV: Application of global adjustment to exports.....	109
1. Introduction.....	109
2. Importance of issue and motivation of analytical approach.....	109
2.1. Importance of issue.....	110
2.2. Motivation of analytical approach.....	110
3. Analytical approach and anticipated effects.....	113
3.1. Counterfactual equilibrium	113
3.2. Cases considered	117

4. Empirical results	118
4.1. Counterfactual equilibrium	119
4.2. Cases considered	125
5. Discussion.....	127
5.1. Pro rata ($z = 1$).....	127
5.2. Maximum total surplus.....	130
5.3. Maximum Ontario consumers' surplus	132
5.4. Comparison of alternative allocation rules.....	134
6. Conclusions	135
6.1. Future research	136
 Chapter V: The market for short-term financial transmission rights.....	 139
1. Introduction.....	139
2. Financial transmission rights.....	142
2.1. Characteristics.....	143
2.2. Demand.....	144
2.3. Supply	145
2.4. Auction market.....	146
2.5. Benefits of financial transmission rights and associated markets	146
2.5.1. FTRs as hedging instruments	146
2.5.2. Prediction of magnitude of congestion.....	151
3. Theoretical characterisation of an informationally efficient forward market and econometric approaches to the assessment of forward market unbiasedness	152
3.1. Censored dependent variable.....	154
3.2. Path-by-path and seemingly unrelated regression approaches.....	155
3.3. Panel data approach.....	156
4. Previous analyses of forward market unbiasedness	156
4.1. Unbiasedness and financial transmission rights.....	156
4.2. Unbiasedness and non-FTR markets	161
5. Data for FTR analysis	163

5.1.	Aggregate FTR profitability and the relative importance of FTR durations.....	163
5.2.	Definitions	165
5.3.	Data for ST FTR analysis.....	167
5.3.1.	Limitations of ST FTR analysis due to auction process and missing data	167
5.3.2.	Rates of profitability of ST FTRs	169
5.3.3.	Basic relationship between MCP and payout.....	171
5.3.4.	Stationarity	173
5.3.5.	Incidence of ST FTR censoring.....	174
5.4.	Data sources	175
6.	Econometric models, hypotheses, and methodology	175
6.1.	Model specification	175
6.2.	Regressors and anticipated marginal effects	178
6.2.1.	Controlling for demand variation.....	178
6.2.2.	Natural gas generation and prices.....	181
6.2.3.	Other variables.....	182
6.3.	Hypothesis testing	183
6.3.1.	Summary of hypotheses considered.....	183
6.3.2.	Informational efficiency/forward market unbiasedness hypothesis..	184
6.3.3.	Learning hypothesis: convergence over time.....	185
6.3.4.	Learning hypothesis: realised error adjustment	186
6.4.	Methodology.....	186
7.	Econometric results and discussion.....	187
7.1.	Summary of econometric approaches	188
7.2.	Results and discussion of ST FTR with panel data.....	189
7.2.1.	Pooled cross-section estimators	189
7.2.2.	Fixed- and random-effects	191
7.2.3.	Comparison of fixed- and random-effects approaches.....	195
7.2.4.	Summary of results of panel data analysis of ST FTRs.....	197

7.3.	Results and discussion of ST FTRs with individual transmission path data	198
7.3.1.	OLS estimator.....	199
7.3.2.	Tobit estimator.....	202
7.3.3.	Two-stage Heckman estimator	207
8.	Conclusions	215
8.1.	Summary of results.....	215
8.2.	Future research	216
Chapter VI: The market for long-term financial transmission rights		217
1.	Introduction.....	217
2.	Additional considerations	217
2.1.	Auction market.....	218
2.2.	Overlapping data	218
3.	Data	220
3.1.	Timeframe and the overlapping nature of the data	220
3.2.	Limitations of analysis due to missing data	220
3.3.	Profitability of LT FTR ownership	222
3.4.	Basic relationship between MCP and payout	225
3.5.	Benefits of a two-round auction structure.....	226
3.6.	Incidence of censoring	230
3.7.	Stationarity	231
4.	Econometric models, hypotheses, and methodology	232
4.1.	Econometric models and hypotheses	232
4.2.	Methodology.....	233
5.	Results and discussion	233
5.1.	Overlapping observations.....	234
5.1.1.	Pooled linear estimator with overlapping observations	234
5.1.2.	Fixed- and random-effects estimator with overlapping observations	235
5.2.	Summary of results of panel data analysis of LT FTRs with overlapping observations.....	237

5.3.	Non-overlapping observations.....	237
5.3.1.	Pooled linear estimator with non-overlapping observations.....	237
5.3.2.	Fixed- and random-effects estimator with non-overlapping observations	238
5.3.3.	Summary of results of panel data analysis of LT FTRs with non-overlapping observations.....	240
6.	Conclusions	240
6.1.	Future research	241
Chapter VII: Bidding in financial transmission rights auctions		243
1.	Introduction.....	243
2.	Literature review	245
2.1.	Bidding in Ontario's FTR auction market.....	245
2.2.	Count-data in other contexts	246
3.	Economic issues of interest	247
3.1.	Structure of external market	248
3.2.	Number of FTRs available	251
3.3.	Previously observed congestion.....	251
3.4.	Deterministic variables.....	252
4.	Data and descriptive statistics	253
4.1.	Count of auctions	253
4.2.	Structure of external markets.....	255
4.3.	Available FTRs	256
4.4.	Previously observed congestion.....	258
5.	Methodology	261
5.1.	OLS regression	262
5.2.	Poisson regression and parameterisation.....	263
5.2.1.	Poisson distribution.....	263
5.2.2.	Estimation method	264
5.2.3.	Parameterisation	264
5.2.4.	Interpretation of estimates	266

5.3.	Alternatives to Poisson regression	267
5.3.1.	Negative binomial regression	267
5.3.2.	Gamma regression model	269
6.	Empirical results and discussion	271
6.1.	Empirical results	271
6.2.	Discussion	274
7.	Conclusions	278
Chapter VIII: Conclusion		281
References		287
Appendices		298
Appendix II-A: Global adjustment reform of 2010		298
Appendix II-B: Structure of global adjustment expenses		301
Appendix II-C: Solution to the model		307
Appendix V-A: Acronyms		315
Appendix V-B: Numerical Example of an FTR		316
Appendix V-C: Complete List of Transmission Paths		318
Appendix V-D: ST FTR data and statistics		319
Appendix V-E: Estimation results for pooled ST FTR data		324
Appendix V-F: Estimation results for path-by-path OLS analysis with ST FTR data		335
Appendix V-G: Estimation results for path-by-path Tobit analysis with ST FTR data..		374
Appendix V-H: Estimation results for path-by-path, two-stage analysis with ST FTR data		400
Appendix VI-A: LT FTR data and statistics		441
Appendix VI-B: Estimation results with LT FTR data		448

List of Tables

Table II-1: Summary statistics of endogenous variables.....	33
Table II-2: Summary statistics of exogenous variables.....	33
Table II-3: Panel A: Estimation of Ontario-based Supply Equation.....	36
Table II-3: Panel B: Estimation of Import Equation.....	37
Table II-3: Panel C: Estimation of Ontario-based Demand Equation.....	37
Table II-3: Panel D: Estimation of Export Equation.....	37
Table II-4: Price Elasticity Estimates.....	43
Table II-5: Mean and standard deviation of observed and base case endogenous variables, All months and last 24 months.....	57
Table III-1: Base case and no-renewable energy counterfactual policy statistics, All months and last 24 months.....	86
Table III-2: Changes of surplus under the counterfactual policy, By economic agent on an hourly basis, in dollars, All months and last 24 months.....	92
Table III-3: Changes of surplus under the counterfactual policy, By economic agent on a monthly basis, in millions of dollars, All months and last 24 months.....	92
Table III-4: Change of CO ₂ emissions, amount as noted, hourly and monthly basis, All months and last 24 months.....	97
Table III-5: Cost of CO ₂ emission-abatement, Dollars per tonne of CO ₂ (\$/tonne), Renewable energy in place of natural gas, Based on total surplus and Ontario- based consumers' surplus alone, All months and last 24 months.....	99
Table III-6: Cost of CO ₂ emission-abatement, Dollars per tonne of CO ₂ (\$/tonne), Renewable energy in place of coal, Based on total surplus and Ontario-based consumers' surplus alone, All months and last 24 months.....	99
Table III-7: Bootstrapped cost of CO ₂ emission-abatement, Dollars per tonne of CO ₂ (\$/tonne), Renewable energy in place of natural gas or coal, Based on total surplus.....	103
Table IV-1: Endogenous variables under base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual, all months and last 24 months, Units defined in Table II-1.....	120
Table V-1: Aggregate FTR auction revenue for imports and exports, by duration (millions of dollars unless noted).....	163

Table V-2: Aggregate FTR payouts for imports and exports, by duration (millions of dollars unless noted).....	164
Table V-3: ST FTR: Path-by-path summary of missing observations.....	168
Table V-4: Average and median rates of return to ST FTRs.....	171
Table V-5: Cumulative return to ST FTRs.....	171
Table V-6: ST FTR: Stationarity.....	173
Table V-7: ST FTR: Incidence of censoring for paths under consideration.....	174
Table V-8: Composition of $X_{p,t} * \gamma$	176
Table V-9: Summary of tested hypotheses.....	183
Table V-10: ST FTR: Summary of econometric approaches using panel data.....	188
Table V-11: ST FTR: Summary of econometric approaches with group-level data.....	188
Table VI-1: LT FTR: Path-by-path summary of missing observations.....	221
Table VI-2: Average and median rates of return to LT FTRs, Units defined as in Table V-4.....	224
Table VI-3: Cumulative return to LT FTRs, Units defined as in Table V-4.....	224
Table VI-4: Second-round price discovery, Average dollars per FTR.....	228
Table VI-5: Summary statistics regarding second-round discovery and related t-test, Average dollars per FTR.....	229
Table VI-6: LT FTR: Incidence of censoring for paths.....	230
Table VI-7: LT FTR: Stationarity.....	232
Table VI-8: LT FTR: Summary of econometric approaches using panel data.....	233
Table VII-1: Number of FTR auctions, by transmission path.....	253
Table VII-2: Summary statistics of number of bidders.....	255
Table VII-3: Average number of FTRs available at auction.....	257
Table VII-4: Econometric estimation results.....	272
Table VII-5: Marginal effects and incidence-rate ratios.....	273
Table Appendix V-C: Complete List of Transmission Paths.....	318
Table V-D1: ST FTR: MCP and payout summary statistics ignoring path distinction...	319
Table V-D2: ST FTR: MCP and payout summary statistics for import paths.....	319
Table V-D3: ST FTR: MCP and payout summary statistics for export paths.....	319
Table V-D4: ST FTR: Summary Statistics for ex-post profits.....	319
Table V-D5: ST FTR: Correlation between MCP and payout and its statistical significance for paths under consideration.....	320

Table V-D6: ST FTR: Summary statistics for various additional variables.....	320
Table V-E1: OLS on pooled cross-section: Estimates and diagnostic tests.....	324
Table V-E2: OLS on pooled cross-section: Hypothesis test results.....	325
Table V-E3: Tobit on pooled cross-section: Estimates and diagnostic tests.....	326
Table V-E4: Tobit on pooled cross-section: Hypothesis test results.....	327
Table V-E5: Panel data with fixed path-specific effects: Estimates and diagnostic tests.....	327
Table V-E6: Panel data with fixed path-specific effects: Hypothesis test results.....	328
Table V-E7: Tobit with dummy variables on pooled cross-section: Estimates and diagnostic tests.....	329
Table V-E8: Tobit with dummy variables on pooled cross-section: Hypothesis test results.....	330
Table V-E9: Panel Tobit with fixed-effects: Estimates and diagnostic tests.....	330
Table V-E10: Panel Tobit with fixed-effects: Hypothesis test results.....	331
Table V-E11: Panel data with random path-specific effects: Estimates and diagnostic tests.....	331
Table V-E12: Panel data with random path-specific effects: Hypothesis test results.....	332
Table V-E13: Tobit with random path-specific effects: Estimates and diagnostic tests.....	332
Table V-E14: Tobit with random path-specific effects: Hypothesis test results.....	333
Table V-E15: Hausman test: Comparison of linear fixed- and random-effects models.....	333
Table V-E16: Hausman-like comparison: Estimates of β under censored data estimators.....	334
Table V-F1: Panel A: OLS: misi to onzn: Estimates and diagnostic tests.....	335
Table V-F1: Panel B: OLS: misi to onzn: Estimates and diagnostic tests.....	336
Table V-F1: Panel C: OLS: misi to onzn: Estimates and diagnostic tests.....	338
Table V-F1: Panel D: OLS: misi to onzn: Estimates and diagnostic tests.....	339
Table V-F2: Panel A: OLS: misi to onzn: Hypothesis test results.....	340
Table V-F2: Panel B: OLS: misi to onzn: Hypothesis test results.....	341
Table V-F2: Panel C: OLS: misi to onzn: Hypothesis test results.....	341
Table V-F2: Panel D: OLS: misi to onzn: Hypothesis test results.....	341
Table V-F3: Panel A: OLS: nysi to onzn: Estimates and diagnostic tests.....	342

Table V-F3: Panel B: OLS: nysi to onzn: Estimates and diagnostic tests.....	343
Table V-F3: Panel C: OLS: nysi to onzn: Estimates and diagnostic tests.....	345
Table V-F3: Panel D: OLS: nysi to onzn: Estimates and diagnostic tests.....	346
Table V-F4: Panel A: OLS: nysi to onzn: Hypothesis test results.....	347
Table V-F4: Panel B: OLS: nysi to onzn: Hypothesis test results.....	348
Table V-F4: Panel C: OLS: nysi to onzn: Hypothesis test results.....	348
Table V-F4: Panel D: OLS: nysi to onzn: Hypothesis test results.....	348
Table V-F5: Panel A: OLS: onzn to misi: Estimates and diagnostic tests.....	349
Table V-F5: Panel B: OLS: onzn to misi: Estimates and diagnostic tests.....	350
Table V-F5: Panel C: OLS: onzn to misi: Estimates and diagnostic tests.....	352
Table V-F5: Panel D: OLS: onzn to misi: Estimates and diagnostic tests.....	353
Table V-F6: Panel A: OLS: onzn to misi: Hypothesis test results.....	354
Table V-F6: Panel B: OLS: onzn to misi: Hypothesis test results.....	355
Table V-F6: Panel C: OLS: onzn to misi: Hypothesis test results.....	355
Table V-F6: Panel D: OLS: onzn to misi: Hypothesis test results.....	355
Table V-F7: Panel A: OLS: onzn to nysi: Estimates and diagnostic tests.....	356
Table V-F7: Panel B: OLS: onzn to nysi: Estimates and diagnostic tests.....	357
Table V-F7: Panel C: OLS: onzn to nysi: Estimates and diagnostic tests.....	359
Table V-F7: Panel D: OLS: onzn to nysi: Estimates and diagnostic tests.....	360
Table V-F8: Panel A: OLS: onzn to nysi: Hypothesis test results.....	361
Table V-F8: Panel B: OLS: onzn to nysi: Hypothesis test results.....	362
Table V-F8: Panel C: OLS: onzn to nysi: Hypothesis test results.....	362
Table V-F8: Panel D: OLS: onzn to nysi: Hypothesis test results.....	362
Table V-F9: Panel A: SUR estimates for configuration (I).....	363
Table V-F9: Panel B: SUR estimates for configuration (II)	363
Table V-F9: Panel C: SUR estimates for configuration (III).....	364
Table V-F9: Panel D: SUR estimates for configuration (IV).....	365
Table V-F9: Panel E: SUR estimates for configuration (V).....	366
Table V-F9: Panel F: SUR estimates for configuration (VI).....	366
Table V-F9: Panel G: SUR estimates for configuration (VII).....	367
Table V-F9: Panel H: SUR estimates for configuration (VIII).....	368
Table V-F10: SUR: misi to onzn: Hypothesis test results: Panel A.....	369
Table V-F10: SUR: misi to onzn: Hypothesis test results: Panel B.....	369

Table V-F11: SUR: nysi to onzn: Hypothesis test results: Panel A.....	370
Table V-F11: SUR: nysi to onzn: Hypothesis test results: Panel B.....	370
Table V-F12: SUR: onzn to misi: Hypothesis test results: Panel A.....	370
Table V-F12: SUR: onzn to misi: Hypothesis test results: Panel B.....	371
Table V-F13: SUR: onzn to nysi: Hypothesis test results: Panel A.....	371
Table V-F13: SUR: onzn to nysi: Hypothesis test results: Panel B.....	371
Table V-F14: SUR: All paths jointly: Hypothesis test results: Panel A.....	372
Table V-F14: SUR: All paths jointly: Hypothesis test results: Panel B.....	372
Table V-F15: 90% confidence intervals for MCP: Panel A: misi to onzn.....	372
Table V-F15: 90% confidence intervals for MCP: Panel B: nysi to onzn.....	373
Table V-F15: 90% confidence intervals for MCP: Panel C: onzn to misi.....	373
Table V-F15: 90% confidence intervals for MCP: Panel D: onzn to nysi.....	373
Table V-G1: Panel A: Tobit: misi to onzn: Estimates and diagnostic tests.....	374
Table V-G1: Panel B: Tobit: misi to onzn: Estimates and diagnostic tests.....	374
Table V-G1: Panel C: Tobit: misi to onzn: Estimates and diagnostic tests.....	376
Table V-G1: Panel D: Tobit: misi to onzn: Estimates and diagnostic tests.....	377
Table V-G2: Panel A: Tobit: misi to onzn: Hypothesis test results.....	378
Table V-G2: Panel B: Tobit: misi to onzn: Hypothesis test results.....	379
Table V-G2: Panel C: Tobit: misi to onzn: Hypothesis test results.....	379
Table V-G2: Panel D: Tobit: misi to onzn: Hypothesis test results.....	379
Table V-G3: Panel A: Tobit: nysi to onzn: Estimates and diagnostic tests.....	380
Table V-G3: Panel B: Tobit: nysi to onzn: Estimates and diagnostic tests.....	380
Table V-G3: Panel C: Tobit: nysi to onzn: Estimates and diagnostic tests.....	382
Table V-G3: Panel D: Tobit: nysi to onzn: Estimates and diagnostic tests.....	383
Table V-G4: Panel A: Tobit: nysi to onzn: Hypothesis test results.....	384
Table V-G4: Panel B: Tobit: nysi to onzn: Hypothesis test results.....	384
Table V-G4: Panel C: Tobit: nysi to onzn: Hypothesis test results.....	385
Table V-G4: Panel D: Tobit: nysi to onzn: Hypothesis test results.....	385
Table V-G5: Panel A: Tobit: onzn to misi: Estimates and diagnostic tests.....	386
Table V-G5: Panel B: Tobit: onzn to misi: Estimates and diagnostic tests.....	386
Table V-G5: Panel C: Tobit: onzn to misi: Estimates and diagnostic tests.....	388
Table V-G5: Panel D: Tobit: onzn to misi: Estimates and diagnostic tests.....	389
Table V-G6: Panel A: Tobit: onzn to misi: Hypothesis test results.....	390

Table V-G6: Panel B: Tobit: onzn to misi: Hypothesis test results.....	390
Table V-G6: Panel C: Tobit: onzn to misi: Hypothesis test results.....	391
Table V-G6: Panel D: Tobit: onzn to misi: Hypothesis test results.....	391
Table V-G7: Panel A: Tobit: onzn to nysi: Estimates and diagnostic tests.....	392
Table V-G7: Panel B: Tobit: onzn to nysi: Estimates and diagnostic tests.....	392
Table V-G7: Panel C: Tobit: onzn to nysi: Estimates and diagnostic tests.....	394
Table V-G7 Panel D: Tobit: onzn to nysi: Estimates and diagnostic tests.....	395
Table V-G8: Panel A: Tobit: onzn to nysi: Hypothesis test results.....	396
Table V-G8: Panel B: Tobit: onzn to nysi: Hypothesis test results.....	396
Table V-G8: Panel C: Tobit: onzn to nysi: Hypothesis test results.....	397
Table V-G8: Panel D: Tobit: onzn to nysi: Hypothesis test results.....	397
Table V-G9: Panel A: Tobit: All paths jointly: Hypothesis test results.....	397
Table V-G9: Panel B: Tobit: All paths jointly: Hypothesis test results.....	398
Table V-G10: Panel A: 90% confidence intervals for MCP: misi to onzn.....	398
Table V-G10: Panel B: 90% confidence intervals for MCP: nysi to onzn.....	398
Table V-G10: Panel C: 90% confidence intervals for MCP: onzn to misi.....	399
Table V-G10: Panel D: 90% confidence intervals for MCP: onzn to nysi.....	399
Table V-H1: Panel A: First-stage: misi to onzn: Probit estimates.....	400
Table V-H1: Panel B: First-stage: nysi to onzn: Probit estimates.....	400
Table V-H1: Panel C: First-stage: onzn to misi: Probit estimates.....	401
Table V-H1: Panel D: First-stage: onzn to nysi: Probit estimates.....	401
Table V-H2: Consistency test of first-stage probit estimates.....	402
Table V-H3: Panel A: Second-stage: misi to onzn: Estimates and diagnostic tests.....	402
Table V-H3: Panel B: Second-stage: misi to onzn: Estimates and diagnostic tests.....	403
Table V-H3: Panel C: Second-stage: misi to onzn: Estimates and diagnostic tests.....	405
Table V-H3: Panel D: Second-stage: misi to onzn: Estimates and diagnostic tests.....	406
Table V-H4: Panel A: Second-stage: misi to onzn: Hypothesis test results.....	407
Table V-H4: Panel B: Second-stage: misi to onzn: Hypothesis test results.....	408
Table V-H4: Panel C: Second-stage: misi to onzn: Hypothesis test results.....	408
Table V-H4: Panel D: Second-stage: misi to onzn: Hypothesis test results.....	408
Table V-H5: Panel A: Second-stage: nysi to onzn: Estimates and diagnostic tests.....	409
Table V-H5: Panel B: Second-stage: nysi to onzn: Estimates and diagnostic tests.....	410
Table V-H5: Panel C: Second-stage: nysi to onzn: Estimates and diagnostic tests.....	412

Table V-H5: Panel D: Second-stage: nysi to onzn: Estimates and diagnostic tests.....	413
Table V-H6: Panel A: Second-stage: nysi to onzn: Hypothesis test results.....	414
Table V-H6: Panel B: Second-stage: nysi to onzn: Hypothesis test results.....	415
Table V-H6: Panel C: Second-stage: nysi to onzn: Hypothesis test results.....	415
Table V-H6: Panel D: Second-stage: nysi to onzn: Hypothesis test results.....	415
Table V-H7: Panel A: Second-stage: onzn to misi: Estimates and diagnostic tests.....	416
Table V-H7: Panel B: Second-stage: onzn to misi: Estimates and diagnostic tests.....	417
Table V-H7: Panel C: Second-stage: onzn to misi: Estimates and diagnostic tests.....	419
Table V-H7: Panel D: Second-stage: onzn to misi: Estimates and diagnostic tests.....	420
Table V-H8: Panel A: Second-stage: onzn to misi: Hypothesis test results.....	421
Table V-H8: Panel B: Second-stage: onzn to misi: Hypothesis test results.....	422
Table V-H8: Panel C: Second-stage: onzn to misi: Hypothesis test results.....	422
Table V-H8: Panel D: Second-stage: onzn to misi: Hypothesis test results.....	422
Table V-H9: Panel A: Second-stage: onzn to nysi: Estimates and diagnostic tests.....	423
Table V-H9: Panel B: Second-stage: onzn to nysi: Estimates and diagnostic tests.....	424
Table V-H9: Panel C: Second-stage: onzn to nysi: Estimates and diagnostic tests.....	426
Table V-H9: Panel D: Second-stage: onzn to nysi: Estimates and diagnostic tests.....	427
Table V-H10: Panel A: Second-stage: onzn to nysi: Hypothesis test results.....	428
Table V-H10: Panel B: Second-stage: onzn to nysi: Hypothesis test results.....	429
Table V-H10: Panel C: Second-stage: onzn to nysi: Hypothesis test results.....	429
Table V-H10: Panel D: Second-stage: onzn to nysi: Hypothesis test results.....	429
Table V-H11: Panel A: Second-stage: SUR estimates for configuration (I).....	430
Table V-H11: Panel B: Second-stage: SUR estimates for configuration (II).....	430
Table V-H11: Panel C: Second-stage: SUR estimates for configuration (III).....	431
Table V-H11: Panel D: Second-stage: SUR estimates for configuration (IV).....	432
Table V-H11: Panel E: Second-stage: SUR estimates for configuration (V).....	433
Table V-H11: Panel F: Second-stage: SUR estimates for configuration (VI).....	433
Table V-H11: Panel G: Second-stage: SUR estimates for configuration (VII).....	434
Table V-H11: Panel H: Second-stage: SUR estimates for configuration (VIII).....	435
Table V-H12: SUR: misi to onzn: Hypothesis test results: Panel A.....	436
Table V-H12: SUR: misi to onzn: Hypothesis test results: Panel B.....	436
Table V-H13: SUR: nysi to onzn: Hypothesis test results: Panel A.....	437
Table V-H13: SUR: nysi to onzn: Hypothesis test results: Panel B.....	437

Table V-H14: SUR: onzn to misi: Hypothesis test results: Panel A.....	437
Table V-H14: SUR: onzn to misi: Hypothesis test results: Panel B.....	438
Table V-H15: SUR: onzn to nysi: Hypothesis test results: Panel A.....	438
Table V-H15: SUR: onzn to nysi: Hypothesis test results: Panel B.....	438
Table V-H16: SUR: All paths jointly: Hypothesis test results: Panel A.....	439
Table V-H16: SUR: All paths jointly: Hypothesis test results: Panel B.....	439
Table V-H17: SUR: Panel A: misi to onzn: 90% confidence intervals for MCP.....	439
Table V-H17: SUR: Panel B: nysi to onzn: 90% confidence intervals for MCP.....	440
Table V-H17: SUR: Panel C: onzn to misi: 90% confidence intervals for MCP.....	440
Table V-H17: SUR: Panel D: onzn to nysi: 90% confidence intervals for MCP.....	440
Table VI-A1: LT FTR: MCP and payout summary statistics ignoring path distinction.....	441
Table VI-A2: LT FTR: MCP and payout summary statistics for import paths.....	441
Table VI-A3: LT FTR: MCP and payout summary statistics for export paths.....	442
Table VI-A4: LT FTR: Summary statistics for ex-post profits.....	442
Table VI-A5: LT FTR: Correlation between MCP and payout and its statistical significance.....	443
Table VI-A6: LT FTR: Summary statistics for various additional variables.....	443
Table VI-B1: OLS on pooled cross-section with overlapping data: Estimates and diagnostic tests.....	448
Table VI-B2: OLS on pooled cross-section with overlapping data: Hypothesis test results.....	449
Table VI-B3: Fixed path-specific effects with overlapping data: Estimates and diagnostic tests.....	449
Table VI-B4: Fixed path-specific effects with overlapping data: Hypothesis test results.....	450
Table VI-B5: Random path-specific effects with overlapping data: Estimates and diagnostic tests.....	450
Table VI-B6: Random path-specific effects with overlapping data: Hypothesis test results.....	451
Table VI-B7: Hausman test: Comparison of fixed- and random-effects models with overlapping data.....	451

Table VI-B8: OLS on pooled cross-section with non-overlapping data: Estimates and diagnostic tests.....	452
Table VI-B9: OLS on pooled cross-section with non-overlapping data: Hypothesis test results.....	453
Table VI-B10: Fixed path-specific effects with non-overlapping data: Estimates and diagnostic tests.....	453
Table VI-B11: Fixed path-specific effects with non-overlapping data: Hypothesis test results.....	454
Table VI-B12: Random path-specific effects with non-overlapping data: Estimates and diagnostic tests.....	454
Table VI-B13: Random path-specific effects with overlapping data: Hypothesis test results.....	455
Table VI-B14: Hausman test: Comparison of fixed- and random-effects models with non-overlapping data.....	455

List of Figures

Figure II-1: Marginal supplier breaks even.....	5
Figure II-2: Marginal supplier earns quasi-rents.....	5
Figure II-3: Wholesale market price, global adjustment, and the all-in price.....	31
Figure II-4: Ontario-based demand and supply.....	32
Figure II-5: Exports and imports.....	32
Figure II-6: Base case Ontario-based supply.....	45
Figure II-7: Base case import supply.....	46
Figure II-8: Base case aggregate supply.....	47
Figure II-9: Base case Ontario-based demand.....	49
Figure II-10: Base case export demand.....	50
Figure II-11: Base case market demand.....	51
Figure II-12: Base case wholesale market equilibrium.....	54
Figure II-13: Observed and base case wholesale market price.....	57
Figure II-14: Observed and base case global adjustment.....	58
Figure II-15: Observed and base case all-in price.....	58
Figure II-16: Observed and base case equilibrium quantities.....	59
Figure III-1: Capacity of renewable energy generators, by fuel type.....	64
Figure III-2: Output of renewable energy generators, all fuel types.....	65
Figure III-3: Average contract price of renewable generation.....	65
Figure III-4: Average contract price of renewable energy and other prices.....	66
Figure III-5: Changing surplus of Ontario-based supply.....	78
Figure III-6: Changing surplus of import supply.....	79
Figure III-7: Changing surplus of Ontario-based demand.....	81
Figure III-8: Changing surplus of export demand.....	82
Figure III-9: Base case and no-renewable energy counterfactual policy wholesale market clearing price.....	87
Figure III-10: Base case and no-renewable energy counterfactual policy global adjustment.....	88
Figure III-11: Base case and no-renewable energy counterfactual policy all-in price.....	89
Figure III-12: Changes of surplus, by groups of economic agents, hourly basis.....	93

Figure III-13: Change of total surplus, hourly basis.....	93
Figure III-14: Changes of surplus, by groups of economic agents, monthly basis.....	94
Figure III-15: Change of total surplus, monthly basis.....	94
Figure III-16: Change of CO ₂ emissions, hourly basis.....	98
Figure III-17: Change of CO ₂ emissions, monthly basis.....	98
Figure III-18: Cost of CO ₂ emission-abatement with renewable energy in place of natural gas.....	101
Figure III-19: Cost of CO ₂ emission-abatement with renewable energy in place of coal.....	101
Figure III-20: Distribution of cost of CO ₂ emission-abatement, in \$/tonne of CO ₂ emission-abatement with natural gas as the replacement fuel.....	104
Figure III-21: Distribution of cost of CO ₂ emission-abatement, in \$/tonne of CO ₂ emission-abatement with coal as the replacement fuel.....	104
Figure IV-1: Wholesale market clearing price time series, Base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual.....	121
Figure IV-2: Global adjustment time series, Base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual.....	121
Figure IV-3: All-in price time series, Base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual.....	122
Figure IV-4: Wholesale market price, GA rate, Ontario all-in price, and export price, various z	122
Figure IV-5: Wholesale market clearing price, Ontario all-in price, and export price, various z	123
Figure IV-6: Ontario-based demand, exports, Ontario-based supply, and imports, various z	123
Figure IV-7: Change of surplus, by group of economic agents at various values of z	124
Figure IV-8: Change of surplus of Ontario-based consumers at various values of z	124
Figure IV-9: Change of total surplus at various values of z	125
Figure V-1: Distribution of rates of return to ST FTRs, by imports/exports.....	170
Figure VI-1: Distribution of rates of return to LT FTRs, by imports/exports.....	223
Figure VII-1: Frequency distribution of the number of bidders.....	254
Figure VII-2: Available FTRs and number of bidders.....	257
Figure VII-3: First and second lag of payout and number of bidders.....	259

Figure VII-4: First and second lag of proportion of hours congested and number of bidders.....	261
Figure V-D1: Scatter plot of MCP against payout for paths under consideration, Panel A: All paths together.....	321
Figure V-D1: Scatter plot of MCP against payout for paths under consideration, Panel B: Path-by-path.....	322
Figure V-D2: ST FTR: Time series plots of MCP and payout for paths under consideration.....	323
Figure VI-A1: LT FTR: Scatter plot of MCP against payout for all paths.....	444
Figure VI-A2: LT FTR: Scatter plots of MCP against payout for import paths, Panel A: Non-Quebec import paths.....	445
Figure VI-A2: LT FTR: Scatter plots of MCP against payout for import paths, Panel B: Quebec import paths.....	445
Figure IV-A7: LT FTR: Scatter plots of MCP against payout for export paths.....	446
Figure IV-A8: LT FTR: Time series plots of MCP and payout for import paths, Panel A: Non-Quebec import paths.....	446
Figure IV-A8: LT FTR: Time series plots of MCP and payout for import paths, Panel B: Quebec import paths.....	447
Figure IV-A9: LT FTR: Time series plots of MCP and payout for export paths.....	447

List of Appendices

Appendix II-A: Global adjustment reform of 2010	298
Appendix II-B: Structure of global adjustment expenses	301
Appendix II-C: Solution to the model	307
Appendix V-A: Acronyms	3155
Appendix V-B: Numerical Example of an FTR	3166
Appendix V-C: Complete List of Transmission Paths.....	3188
Appendix V-D: ST FTR data and statistics	3199
Appendix V-E: Estimation results for pooled ST FTR data.....	3244
Appendix V-G: Estimation results for path-by-path Tobit analysis with ST FTR data..	3743
Appendix V-H: Estimation results for path-by-path, two-stage analysis with ST FTR data	4009
Appendix VI-A: LT FTR data and statistics	44140
Appendix VI-B: Estimation results with LT FTR data.....	4488

Chapter I: Introduction and purpose

A competitive wholesale electricity market began operation in Ontario in May 2002.

The purpose of this thesis is to undertake an assessment of certain aspects of this market, especially its development during the period after market opening. The aspects of the market to which special attention is paid are (1) issues regarding cost and cost allocation related to implementing certain government policies and (2) the performance of financial transmission rights markets.

The thesis proceeds as follows. Chapter II formulates and estimates a model of Ontario's wholesale electricity market. This model accounts for the behaviour of Ontario-based consumers and producers, inter-jurisdictional trade, and the impact of government policy in the procurement of generation capacity. A fitted base case equilibrium is constructed using this model.

Chapters III and IV report analyses of counterfactual policies, using the base case constructed in chapter II as a benchmark. Two specific counterfactual policies are considered. First, the cost of the provincial government's renewable energy policy is estimated. This is important because there are numerous alternative policies that have been used in different electricity markets to induce entry of renewable electricity generators. Without knowledge of the cost of Ontario's policy there is no theoretically sound way to say whether it is cost efficient or otherwise. Second, the mechanism used to allocate certain costs among consumers that cannot be recovered from the market is considered. In particular, it is current policy that certain costs are not allocated to exports. The impact of allocating these costs to exports at various rates, including at the same rate as they are allocated to Ontario consumers, is considered. This is important because, in the absence of evidence, it is not obvious that the optimal rate at which costs are allocated to exports is zero.

Chapter V tests the forward market unbiasedness hypothesis in relation to Ontario's market for short-term financial transmission rights. This market is important for a number of reasons, among them (1) that participants in the physical electricity market can use these financial instruments to hedge certain risks associated with their operations and (2) that the auction market through which the rights are allocated sends forward-looking signals of congestion in the electricity transmission system that may be valuable to other agents in the wider electricity market. A test of the forward market unbiasedness hypothesis amounts to a general consideration of the usefulness of financial transmission rights.

Chapter VI extends the analysis reported in the previous chapter to Ontario's market for long-term financial transmission rights.

Chapter VII reports an analysis of the determinants of the number of bidders who decide to contest financial transmission rights auctions.

Chapter VIII concludes.

For a more general, theoretical overview of the features and characteristics of electricity markets relevant to economic analysis, see Stoft (2002) and Rothwell and Gomez (2003).

Chapter II: A model of the market

1. Introduction and purpose

A competitive wholesale electricity market began operation in Ontario in May 2002. The purpose of this market is to coordinate production and consumption of electricity in Ontario—including inter-jurisdictional trade—in an economically efficient manner while maintaining electricity system reliability.¹ Prior to May 2002, the functions of what subsequently became the wholesale electricity market were fully integrated components of Ontario Hydro²—a vertically integrated, Province of Ontario crown corporation that managed the generation and transmission of electricity within Ontario, as well as all trade of electricity with neighbouring jurisdictions.

The purpose of a competitive wholesale market is to induce a process whereby optimal use of existing resources, including imports, is incentivised in the short run, while in the long run more efficient sources of supply would drive less efficient sources of supply out of the market. This process, in both time dimensions, is intended to be guided by market-determined prices. In the short run, supply would be drawn from the generating facilities with the lowest incremental cost of production and would be allocated to the consumers with the highest willingness-to-pay. Inter-jurisdictional trade of electricity would occur, subject to potentially binding transmission system constraints, largely as an arbitrage process whereby electricity would flow from

¹ One way to characterise the quality of electricity services is to consider the probability of their availability: the higher the probability, the higher the quality. System reliability refers to maintaining an arbitrarily high value of this characteristic. Since, in a specified jurisdiction, system reliability is both non-excludable and non-rivalrous in its provision and consumption, it is a public good.

² The *Electricity Act, 1998*, abolished Ontario Hydro and replaced it with five distinct entities currently known as Ontario Power Generation Incorporated (OPG), Hydro One Incorporated (HOI), the Independent Electricity System Operator (IESO), the Ontario Electricity Financial Corporation (OEFC), and the Electrical Safety Authority (ESA). The OEFC is the legal successor company to Ontario Hydro.

jurisdictions with low prices to jurisdictions with high prices.³ In the long run, prices would guide producer and consumer decisions that are fixed in the short run.⁴

Under a standard competitive market construct, wholesale market clearing prices would vary through time in response to varying cost and demand conditions and all consumers and producers would pay or be paid, respectively, this price.⁵ With respect to producers, assuming that supply is offered into the market at incremental cost, this means that at any given point in time quasi-rents would be earned by infra-marginal suppliers while the marginal supplier would break even. This situation is illustrated in Figure II-1.⁶ Such quasi-rents, which would be larger in hours with higher prices, are necessary to cover fixed costs. In the long run, the composition of capacity would adjust such that these quasi-rents would exactly cover fixed costs. In practice, while quasi-rents would be earned by some producers at each point in time, there would be a small number of hours characterised by extremely high prices as a result of available supply being exhausted.⁷ It is in these hours that the bulk of fixed costs would be covered, including those of the marginal supplier – which would receive a price in excess of marginal cost since price would be determined based on willingness-to-pay. This situation is illustrated in Figure II-2.⁸

³ The ranking of jurisdictions by price is anticipated to change through time.

⁴ Many characteristics of electricity producers and consumers are fixed in the short run. In the case of producers, these include facility size, location, and fuel type. In the case of consumers, these include location and structure of production facilities (consuming firms), and the choice of appliances and residence size (consuming households).

⁵ The issue of locational pricing is ignored in this thesis. However, had this not been the case the general conclusions would remain intact, except that instead of viewing the Ontario as a single market with a uniform wholesale market clearing price it would be viewed as a set of potentially different sub-markets based on potentially binding physical constraints in the electricity transmission system.

⁶ The illustrations in this section assume generic upward- and downward-sloping market supply and demand functions. $\bar{Q}$ is the amount of generation capacity.

⁷ In Ontario, regulations prevent the absolute value of the wholesale market clearing price from exceeding \$2,000 per MWh.

⁸ See Stoft (2002) for a thorough discussion of the features of competitive electricity markets.

Figure II-1: Marginal supplier breaks even

Figure II-2: Marginal supplier earns quasi-rents

This process envisioned a relatively minor role for regulators regarding the entrance of incremental supply. It was expected that regulators, acting under the authority of the provincial government, would provide various services—such as real-time

management of the transmission and distribution system—critical to the ongoing operation of the wider electricity market by the establishment of an independent system operator. In Ontario, the relevant agency is known as the Independent Electricity System Operator (IESO).

There are a variety of benefits associated with this type of market structure.

Decentralised decision making incentivises a variety of supply and demand responses to changing cost and demand characteristics that cannot typically be made by government-owned and managed monopolies. This is particularly the case in relation to inter-jurisdictional trade, where arbitrage-driven trade is likely to lead to market demand being satisfied at a lower total cost than otherwise. Competitive markets also tend to distribute risk efficiently. In particular, risk tends to be borne by shareholders of generation firms that choose to bear it rather than by electricity consumers (rate-payers) and government (tax-payers), who generally bear it under government-owned monopolies.

Structural reforms were necessitated by the rigidity of the industry in the years before market opening in 2002. Consumer prices, set by government regulation, generated insufficient revenues to cover the costs incurred by Ontario Hydro, thereby resulting in large accumulated losses. With respect to generation capacity, prior to market opening the most recent electricity generator to enter service was the fourth nuclear reactor at Darlington, east of Toronto. Taken together, low prices resulted in a lack of investment in the industry as Ontario Hydro lacked sufficient financial resources and no privately-owned firm had the incentive to propose entry.⁹

⁹ There was an analogous lack of investment in transmission infrastructure. One additional benefit of a competitive market is that it signals the locations (routes) of the most socially valuable transmission infrastructure improvements.

Over the period commencing with the passage of the *Electricity Act, 1998*, in that year and culminating with market opening in 2002, approximately 10,000 MW of incremental capacity – both greenfield (all of which was natural gas-fuelled) and refurbishments of previously exited capacity (all of which was nuclear-fuelled) – had announced plans to enter the market.¹⁰ While it was not clear at the time how much of this proposed incremental capacity would ultimately enter, opening the market certainly induced much private-sector interest in doing so.

It was not immediately clear that the market process described above would fail to achieve the desired long-run equilibrium. However, in the years after market opening it became clear that realised wholesale market clearing prices were, on average, insufficiently high such that the desired long-run equilibrium would indeed not be achieved. This outcome obtained, at least partially, as a result of government and regulatory intervention. In particular, a variety of policies and regulations, some of which were highly technical in nature, had the effect of systematically suppressing the wholesale market clearing price paid by consumers to producers.

For instance, in the process of determining the wholesale market clearing price, electricity generators are treated as being able to change their level of output at a constant multiple of what is technically feasible.^{11, 12} This policy was adopted as a

¹⁰ See the first report of the Market Surveillance Panel, “Monitoring Report on the IMO-Administered Electricity Markets for the First Four Months,” published on 7 October 2002. Note that IMO is the acronym for Independent Market Operator. This was the original name of the Independent Electricity System Operator (IESO), a change made by the *Electricity Restructuring Act, 2004*.

¹¹ The rate at which a particular electricity generator can change its level of output is a technical characteristic of the generator that is known as its ramp rate. For instance, suppose a generator requires 20 minutes to be able to increase its output from 100 MW to 200 MW, then its ramp rate, at least while increasing output over the specified range, is 5 MW per minute. The multiple of this rate that is used by the system operator in the wholesale market clearing price determination process can be thought of as the ramp rate multiplier. Continuing with the example above, if a 12-times multiplier is used by the system operator then the generator would be treated as being able to increase output at a rate of 60 MW per

means of reducing the volatility of the wholesale market clearing price, which it did by treating wholesale market supply as being effectively more price elastic (faster to adjust to a given price change) than is truly feasible. However, the effect was also to systematically suppress the average wholesale market clearing price.¹³ The effect is most meaningful at the most supply-constrained points of time, when the standard market construct described above suggests the bulk of fixed cost is recovered.

A similar example relates to the treatment of inter-jurisdictional trade—a treatment that systematically suppresses the wholesale market clearing price.¹⁴

As a result of this outcome, a restructuring of the wholesale market began in 2004 with the passage of the *Electricity Restructuring Act, 2004*, which among other things, amended the *Electricity Act, 1998*. The key impact of this Act was the creation of the Ontario Power Authority (OPA).¹⁵ One aspect of the OPA's mandate is to act as a long-run electricity system planner.¹⁶ To that end, recognising that entrance of new supply would eventually become necessary and that the market as described above would not achieve this on its own, the OPA initiated a programme of generation procurement—a programme of policy-induced entry of supply. At its beginning, this programme focused on inducing entry of natural gas-fuelled electricity generators so as to

minute. In other words, the generator would be treated as being able to increase its output from 100 MW to 200 MW in 1 minute and 40 seconds rather than the 20 minute duration required physically.

¹² From market opening on 1 May 2002 to 11 September 2007, the ramp rate multiplier was twelve (12). Effective 12 September 2007 onward, it was reduced to three (3).

¹³ This issue was discussed in the second report of the Market Surveillance Panel (MSP, December 2003, p. 112), many times subsequently, and elsewhere.

¹⁴ This issue was discussed in the fourth report of the Market Surveillance Panel (MSP, December 2004, p. 17-8), many times subsequently, and elsewhere.

¹⁵ Bill 75, *Ontario Electricity System Operator Act, 2012*, which is before Ontario's legislative assembly as of 15 June 2012, would merge the IESO and the OPA would be merged into a single entity called the Ontario Electricity System Operator (OESO). The bill can be found at http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=2622&detailPage=bills_detail_debates.

¹⁶ The OPA has numerous additional responsibilities, especially in relation to electricity conservation and usage efficiency. Consideration of these activities is beyond the scope of this chapter.

implement the government's goal of withdrawing coal-fuelled electricity generators from the market.

Later, the mandate of the regulator was augmented to include the inducement of renewable energy generating technologies—principally wind- and solar-fuelled—into the electricity market.¹⁷ While this deepened the extent of government involvement in the market, the structure of the hybrid market was not materially altered.

Due to the *Electricity Restructuring Act, 2004*, Ontario's electricity market became a hybrid market: a competitive wholesale electricity market with a government agency that actively manages supply. One impact of this altered market structure is that, subsequent to its creation, no generation capacity has entered Ontario's electricity market without a contract written under the generation procurement programme. Though the OPA is not a regulator in the classical sense, given its role in actively managing market supply, terminology referring to it as such is adopted herein.

Certain relevant details regarding the generation procurement programme are discussed in this chapter. However, it is immediately clear that any such programme may lead to costs being borne by the regulator.¹⁸ These costs, and the risks associated therewith, are funded through a financial account known as the global adjustment mechanism (GAM).¹⁹ A convention of referring to aggregate costs, measured in dollars, borne by the regulator in month t as GAM_t is adopted.

¹⁷ For instance, a 16 November 2005 ministerial directive required the OPA to enter into contracts with nine wind-fuelled generation firms that had been selected by the Ministry of Energy to construct wind farms in Ontario.

¹⁸ As discussed below, the aggregate costs incurred may be negative. In such an event, this balance is paid out to consumers in an analogous manner to the mechanism that allocates positive costs.

¹⁹ As noted in the detailed discussion regarding the composition of the GAM below, GAM includes significant expenses related to regulatory activities other than the programme of generation procurement. For instance, GAM includes expenses associated with various regulator-directed conservation programmes.

Assuming that funding directly from the provincial treasury is not feasible, some mechanism is required to raise the necessary funds from electricity consumers, *i.e.*, the regulator's budget must be balanced. The specific rule used to allocate GAM costs among consumers shall be referred to as the global adjustment allocation rule (GAAR). From its institution in January 2005, the GAAR was such that all Ontario-based consumers were charged in constant proportion to their own level of total monthly consumption. Export-consumers do not pay this fee. A convention of referring to the rate, measured in dollars per kWh, at which costs are allocated by the regulator in month t as g_t is adopted. Interestingly, the GAAR was altered in an important manner effective January 2011. Given the recent nature of this change and the nature of the adjustment and learning process that will follow, this issue will not be considered in the main body of the chapter, though it is discussed at some length in Appendix II-A.

Had either the regulator's generation procurement initiative or the GAAR been materially different, outcomes observed in Ontario's electricity market would have been materially different. The purpose of this chapter is to assess the hypothetical impact of two such policy counterfactuals. First, the impact of renewable generation procurement is assessed. Second, the impact of altering the GAAR such that export demand is made subject to the costs associated with global adjustment is assessed.

The chapter will proceed as follows. Section 2 describes the methodology employed in the chapter. Section 3 describes in some detail the structure of the wholesale electricity market and the regulator, with particular focus on the impact of policy-induced entrance of supply on the wholesale market equilibrium. Particular attention is paid to the aspects of the market for which hypothetical alternative policies are relevant. This discussion is used to motivate the components of a simultaneous equations model of Ontario's electricity market. Section 4 describes the data. Section 5 describes the econometric techniques and econometric results associated with the estimation of the

market model. Section 6 constructs a base case market equilibrium. Section 7 concludes.

2. Methodology

As stated in section 1, the purpose of this chapter is to assess the impact on the electricity market equilibrium of certain regulatory policies. Such an assessment would be made by determining the difference between the observed equilibrium and certain counterfactual policy equilibria.

The first step is to model the process by which the observed equilibrium obtains. This is called the base case. The second step is to consider the alternative processes by which each counterfactual policy equilibrium obtains. These processes are used to simulate the related counterfactual policy equilibrium, thereby determining the impact of the regulatory policy.

2.1. Step one: the base case

The model is comprised of a system of six equations—corresponding to six endogenously determined variables: Ontario-based supply; imports; Ontario-based demand; exports; the regulator’s budget constraint; and the quantity equilibrium—as specified in section 3 that describe, in simplified terms, the process by which the observed equilibrium obtains. As described there, the first four of these equations must be estimated, while the last two are identities. The four non-identities are estimated as a system of simultaneous equations, with techniques described in section 5. The regulator’s budget constraint must be calibrated with relevant market data.

The fully parameterised system of six equations is then solved for the base case values of each of the six endogenous variables. This process is discussed further in section 6.

2.2. Step two: the counterfactuals

Under each of the counterfactuals considered, at least one aspect of the market would have been different. Critically, the estimated coefficients are assumed to be unaltered. For instance, the estimated coefficient associated with the price paid by exporters of electricity is assumed to be unchanged as a result of the counterfactual policy.

The counterfactual-policy outcomes are constructed by altering either the underlying data series or the regulator's budget constraint as appropriate. The equilibrium impact of each counterfactual policy is then measured by comparison of the simulated counterfactual with the base case. These issues are considered in chapter III.

3. The model: the role of the regulator and the wholesale market

The impact of regulatory policy on the wholesale market equilibrium is of paramount importance in this study. Section 3.1 outlines, with reference to Appendix II-A, the structure of the regulator. Particular attention is given to how its policies mandate the existence of a global adjustment mechanism (GAM) in principle. Section 3.2 outlines the structure of the wholesale market itself, including how the equilibrium wholesale market clearing price and global adjustment rate are determined. Attention is directed to the mechanisms by which regulatory intervention impacts the various components of the market, and therefore its equilibrium.

3.1. The role of the regulator

The government regulator that is relevant in the context of this chapter is the one whose objective is to engage in long-run management of the supply side of Ontario's electricity market: the OPA. To that end—under the direction and authority of numerous directives from the provincial government—the OPA initiated a programme of generation procurement. This programme manifested itself in the form of many

specific procurement initiatives differentiated by generation technology or fuel source, such as nuclear, hydro, natural gas, and wind.²⁰

The contracts that resulted from these procurement initiatives offered signatories terms and, therefore, outcomes that could not be obtained from uncontracted entrance into the wholesale electricity market. The most important effects were to reduce the uncertainty and, in some cases, raise the level of the net present value of the expected revenues of prospective entrants.²¹

From the perspective of the OPA, in any given time period (typically, one month), an individual contract may result in a payment that may be either positive or negative. The aggregate payments to all contracted generation in any time period may, as a consequence of summation, be either positive or negative as well. These costs are allocated to certain groups of consumers as a component of the GAM.

The mechanism by which GA is allocated among consumers has important implications for the functioning of the wholesale electricity market. From its creation in January 2005²² until December 2010 GA costs were allocated among consumers in proportion to their consumption, *i.e.*, GA was levied at a specific rate (g_t , \$ per MWh of consumption). The allocation mechanism was meaningfully altered as of 1 January 2011. The changes are described in Appendix II-A, but are otherwise ignored in this analysis for reasons given there.

²⁰ The structure of individual procurement initiatives varied across initiatives. For instance, the initial wind generation contracts followed from a request-for-proposals process, while all solar generation contracts resulted from individual firm applications to various standard offer processes. The details of these procurement structures are not relevant within the context of this study.

²¹ It is likely the case that a large proportion, if not all, of the supply that entered the market as a result of these contracts would not have entered otherwise.

²² The GA is defined, for the period prior to January 2005, to be zero both in aggregate terms and as a rate.

The impact of the programme of policy-induced entry manifests itself in the wholesale electricity market in two forms. First, supply is greater than it would have otherwise been. Second, the costs imposed through the allocation of GA will impact net-of-GA willingness to pay for electricity. The details of these two effects on various components of the market, as well as market equilibrium, are discussed in the next section.

3.2. The wholesale market

This section outlines the general structure of Ontario's wholesale electricity market.²³ The model of Ontario's electricity market is composed of six distinct equations relating to: (1) Ontario-based supply; (2) imports; (3) Ontario-based demand; (4) exports; (5) the regulator's budget constraint; and (6) a quantity equilibrium condition.

3.2.1. Supply

Supply is offered into Ontario's wholesale electricity market by both Ontario-based generators and importers.

3.2.1.1. Ontario-based supply

Ontario-based supply (q_t^s) relates to electricity produced within Ontario and is endogenously determined within the model. In particular, it does not include imports of electricity to Ontario.

Ontario-based generators produce electricity using a variety of different technologies and fuel sources, and operate under a variety of different contractual arrangements

²³ There are important issues related to real-time management of the electricity market and the time periods in which certain electricity resources are scheduled. In particular, inter-jurisdictional trade is determined and fixed in advance of real time—in the so-called pre-dispatch period. Consideration of such issues is beyond the scope of this study.

relative to the regulator. The regulator's programme of generation procurement impacts wholesale market supply in two respects: offer quantities and offer prices.

The quantity of offers is impacted by the generation procurement programme because it results in generators offering supply that would otherwise not be in the market. In other words, if a generator would not have entered Ontario's market in the absence of regulatory inducement, then the regulator's activity will have raised the quantity of offered supply.

Regulator activities also impact the prices at which generators in the market offer supply. It is assumed that generators offer their production into the wholesale market at their private opportunity cost—which is directly affected by the contractual terms offered by the regulator, if any. Consider two examples. First, a generator operating without a contract will have an opportunity cost equal to its physical incremental cost of supply. It is expected to offer its supply at this price. A detailed discussion of the contract structures relevant to Ontario is provided in Appendix II-B. In short, contracts between the regulator and generators have important effects on supply offers.

Ontario-based electricity producers are paid the wholesale market clearing price (p_t)—in addition to which some generators also receive contractually specified out-of-market payments as described above. Regardless of contract structure, offering below the wholesale market clearing price is a necessary and sufficient condition for receiving dispatch instructions to produce.²⁴

²⁴ Ontario's electricity system operator determines two dispatch schedules. The first is the so-called constrained schedule, which minimises the total cost of meeting demand and accounts for all constraints relevant to the market. Physical dispatch instructions to generators are based on this schedule. The second is the so-called unconstrained schedule, which functions similarly but ignores all (Ontario) internal transmission constraints. While there is no economically sensible reason for any physical constraint to be ignored in the determination of prices, wholesale market prices are based on this schedule.

For some electricity producers the wholesale market clearing price is the critical variable considered in relation to supply offers. For instance, it is generally the case that coal-fuelled thermal generators desire to produce whenever the wholesale market clearing price exceeds their incremental cost. Certain other generators, natural gas-fuelled thermal generators in particular, operate under contracts that include significant lump-sum transfers that are reduced whenever the wholesale market clearing price exceeds their contractually specified incremental costs. The result is that such firms are exposed to wholesale market conditions and tend to produce more output when the wholesale market price is higher. It is expected that Ontario-based supply will be increasing in the wholesale market clearing price.

Presuming that firms exposed to the wholesale market clearing price—such as coal- and natural gas-fuelled generators—will produce whenever that price exceeds incremental cost, offers from Ontario-based electricity producers in the wholesale market will be dependent on the level of those incremental costs. A unitless fuel price index, denoted $fuel_t$ and constructed as the weighted average of Henry Hub natural gas and Central Appalachian coal prices, is taken as a proxy for incremental costs.²⁵ Each commodity trades on the New York Mercantile Exchange. The associated prices are converted into Canadian currency. The weights used in the construction correspond to

²⁵ The Henry Hub is a major natural gas pipeline junction located in Louisiana, United States. Central Appalachia is a major coal-producing region in central part of the Appalachian Mountains, roughly centred on West Virginia. Certain coal-fuelled generators in Ontario—Nanticoke Generating Station and Thunder Bay Generating Station, both owned by the provincial crown corporation Ontario Power Generation—also use coal from the Powder River Basin, located in Montana and Wyoming, United States. The market for coal from the Powder River Basin is smaller, and the price less volatile, than that from Central Appalachia. The Ontario-based generators that use it tend to purchase it under long-term contract, thereby diminishing the importance of the market price from an opportunity cost perspective. These features suggest the price of Central Appalachian coal is relatively more important than the price of Powder River Basin coal.

the relative amount of generation capacity installed in Ontario.²⁶ The fuel price index is assumed to be determined exogenously of Ontario's electricity market. Supply is expected to be decreasing in the level of the fuel price index.

There is a class of producers whose level of production is not dependent on the wholesale market price. Within this class there are three sub-classes: producers whose output is independent of price due to (i) contractual arrangements, (ii) technical generator characteristics, and (iii) environmental conditions.

At the level of a specific firm, contractual arrangements can result in a situation where output is independent of the wholesale market clearing price if the incentives created by the contract result in the wholesale market clearing price—or any other real-time market conditions—not entering the firm's profit function. If the difference between the contract price and the physical incremental costs of supply is positive, the generator will perceive its opportunity cost of supply as being negative, that is, reducing supply by one unit will lead to a loss of contract revenue in excess of the physical incremental cost of supply. Therefore, a profit maximising firm will maximise production. Since, as discussed above, offering below the wholesale market price is a necessary and sufficient condition for being dispatched to produce, such generators will offer into the market at the lowest price allowed. In Ontario, this price is *negative* \$2,000 per MWh. Such contractual arrangements can be referred to as fixed-price contracts and are the type of

²⁶ For instance, if, in a given month t , the amount of coal-fuelled generation capacity was double the amount of natural gas-fuelled generation capacity, the coal price would receive a weight of $\frac{2}{3}$ and the price of natural gas would receive a weight of $\frac{1}{3}$ in the construction of the fuel price index for that month. These weights have changed since market opening, reflecting the construction of new natural gas-fuelled generators and the decommissioning of incumbent (at the time of market opening) coal-fuelled generators. Since the fuel *mix* is largely a matter of public policy, the weights are assumed to be determined exogenously of the wholesale electricity market. Indeed, coal is currently planned to be completely eliminated as a fuel in Ontario as a result of provincial government policy.

contracts under which renewable resource generators,²⁷ non-utility generators (NUGs), and most nuclear generators operate in Ontario.

Another situation where output may be independent of the wholesale market clearing price is as a result of the technical characteristics of the generation technology. For instance, nuclear powered generators have relatively limited ability to vary their level of output when in operation and, as a result, tend to produce output at or near their maximum capacity whenever in operation.²⁸ Following shutdown, such generation facilities often require several days before production can resume. As a result, output tends to be independent of the wholesale market clearing price.

Finally, output will be independent of the wholesale market clearing price if its level is determined exogenously by environmental conditions. For instance, hydroelectric generators use elevated water as the variable input in their production process. While it is often the case that such generators can vary their production on an hour-by-hour basis in response to market conditions, aggregate generation on a monthly basis is principally a function of the amount of water available—a characteristic beyond the generator's control. In addition to their contractual arrangements, wind and solar resource generators are additional examples that tend also to be characterised by having a level of output exogenously determined by environmental conditions.

²⁷ The most important renewable resource technology in use in Ontario today, aside from large-scale hydro, is wind power. Solar and, to a lesser extent, biomass resource generators have also been constructed in Ontario. In the case of wind and solar resource generators, profit maximisation by maximisation of output manifests itself as the generator producing output at the greatest feasible level given the quality of inputs, air movement and solar conditions respectively, available at each time. As noted subsequently, see the discussion of the situation where output levels are exogenously determined by environmental conditions.

²⁸ The ability of nuclear powered generators to vary their level of output is relatively limited in the sense of a comparison to other generator resource types. For instance, hydroelectric generators can change their output quickly and repeatedly throughout a single day, including ceasing and resuming production.

Taken together, the electricity generators discussed immediately above—renewables, NUGs, nuclear, and hydro—constitute a class of electricity producers whose level of output is not dependent on the wholesale market clearing price. The production of this class of producers is often referred to as baseload generation ($baseload_t$). Higher levels of exogenously determined baseload generation are synonymous with greater supply. Therefore, it is expected that quantity supplied will be increasing in the quantity baseload generation.

Thus, the specification of the Ontario-based supply curve used in the model is

$$q_t^s = \gamma_0 + \gamma_1 p_t + \gamma_2 fuel_t + \gamma_3 baseload_t + \varepsilon_{1t} \quad (II-1)$$

3.2.1.2. Imports²⁹

In addition to Ontario-based supply, electricity exchanged in Ontario's wholesale market can originate outside of province (q_t^i). Such supply constitutes imports of electricity with respect to Ontario, which are modelled separately from Ontario-based supply so as to avoid constraining the wholesale market clearing price to having the same marginal effect as it does on Ontario-based supply. As a result, imports are permitted to have a different price elasticity than Ontario-based supply. Imports of electricity to Ontario are endogenously determined within the model.

As with Ontario-based supply, imports are expected to be increasing in the wholesale market clearing price (p_t). Given that arbitrage is a critical aspect of the nature of inter-jurisdictional trade, import supply is expected to be relatively more elastic than Ontario-based supply since traders are assumed to actively seek out the highest price jurisdictions in which to offer their power for sale, *i.e.*, traders can easily offer their

²⁹ Inter-jurisdictional trade of electricity is feasible in relation to New York, Michigan, Minnesota, Manitoba, and Quebec.

electricity into other markets. Ontario-based suppliers, on the other hand, must offer their production into Ontario's electricity market if they want to receive a production schedule, irrespective of where they intend their output to ultimately go.³⁰ With data measured in levels and not logs, this feature need not imply anything about the magnitude of the coefficient associated with the wholesale market clearing price relative to its equivalent in the Ontario-based supply equation. Unlike exports, with imports there is no issue regarding global adjustment (g_t).

Imports are also expected to be dependent on contemporaneous market conditions in neighbouring jurisdictions. As prices in neighbouring jurisdictions are assumed to be endogenous with respect to Ontario's wholesale electricity market, such electricity prices cannot be used as a measure of the conditions prevailing in those markets. Instead, the quantity of electricity consumed in New York state (called the New York integrated load and denoted (NY_L_t)) is used as a proxy for market conditions beyond Ontario. With respect to imports, it is expected that, *ceteris paribus*, higher levels of electricity consumption in New York will result in lower levels of imports to Ontario as electricity is likely to be more highly valued in New York than in Ontario under such circumstances.³¹

Finally, electricity is often transmitted between two neighbouring jurisdictions using Ontario's transmission system. The explicit linking of the import and export components of the associated transactions results in a so-called linked-wheel transaction. The Market Surveillance Panel (MSP, January 2009) reports that during the

³⁰ Generators are not allowed to inject power into the electricity system without being selected to do so by the electricity system operator. In other words, generators can only acquire physical transmission rights as a result of offering into the wholesale electricity market.

³¹ A variety of alternative control variables for contemporaneous market conditions in neighbouring jurisdictions were considered. For instance, the market-determined price of electricity in New York was one such candidate. However, there is a collinearity issue between this price and Ontario's wholesale market electricity price. The New York integrated load allows a less problematic indication of demand in New York to be obtained.

seven-month period January to July 2008 there were an unusually large number of linked-wheel transactions through Ontario.³² Since linked-wheel transactions have no net impact on inter-jurisdictional trade, they do not impact Ontario's wholesale market clearing price. They do, however, impact gross imports (and exports) of electricity. To control for the temporary increase of such transactions, a dummy variable equal to one for the seven specified months of 2008 and zero otherwise—denoted $linked_t$ —is included in the model.

Thus, the specification of the import equation used in the model is

$$q_t^i = \delta_0 + \delta_1 p_t + \delta_2 NY_L_t + \delta_3 linked_t + \varepsilon_{2t} \quad (II-2)$$

3.2.2. Demand

Demand for electricity in Ontario's wholesale market arises from Ontario-based consumers and exporters.

3.2.2.1. Ontario-based consumers

Ontario-based demand (q_t^d) relates to electricity consumed within Ontario and is endogenously determined within the model. In particular, it does not include exports of electricity from Ontario.

Ontario-based consumers pay the market clearing price (p_t) as well as global adjustment (g_t) for each unit of consumption. Assuming that consumers respond to the all-in price rather than to its components, as far as price is concerned, consumers will respond to the sum of the market-clearing price and global adjustment ($p_t + g_t$). It is

³² The Market Surveillance Panel (MSP, July 2008) reports that this issue emerged as a result of certain technical characteristics of electricity markets in the United States. The issue was resolved as a result of market rule changes enacted by the New York Independent System Operator in July 2008 (MSP, January 2009).

expected that Ontario-based demand will be decreasing in the all-in price. Both the market clearing price and global adjustment are endogenous variables in the model.³³

Given that indoor climate control—principally space heating and cooling—is one of the most important uses of electricity, consumption is likely to be dependent on ambient temperature. However, in general demand will be neither an increasing nor a decreasing function of temperature. Rather, the impact of a change in ambient temperature on quantity demanded will be dependent on the initial ambient temperature. Thus, if the ambient temperature is relatively low, say 0° C, and assuming that consumers desire to heat a certain amount of space to a particular (higher) temperature, then an increase of the ambient temperature will reduce the amount of electricity required for space heating. Similarly, if the ambient temperature is relatively high, say 30° C, and assuming that consumers desire to cool a certain amount of space to a particular (lower) temperature, then an increase of the ambient temperature will raise the amount of electricity required for space cooling. For these reasons, demand will not be a monotonic function of temperature.

Given the description above regarding the impact of a change of ambient temperature on demand, it is reasonable to conclude that demand is increasing in the extent to which ambient temperature deviates—above or below—from a typical indoor temperature chosen by humans. The concept of a heating degree day (HDD_t) can be used to measure the magnitude by which the ambient temperature is below a specified

³³ Households (and certain other classes of consumers) in Ontario are eligible to participate in the regulated price plan (RPP) designed by the Ontario Energy Board (OEB). Consumers enrolled in the RPP pay specified rates for electricity—either tiered or time-of-use as applicable—that are fixed in advance for six-month periods. The plan is designed to smooth the costs associated with electricity usage. These rates are set based on forecasts of wholesale market energy prices and global adjustment with the intent of recovering the market-determined costs of consumption. At their own discretion, consumers may opt-out of the RPP in favour of a variety of competitively determined alternative contract structures. The remaining RPP-enrolled consumers are expected to have the lowest elasticity of demand of any class of consumers in Ontario’s electricity market.

threshold.³⁴ Consider a threshold of 18° C. The HDD measure for any given day will be the greater of (1) 18° C less the average ambient temperature and (2) zero. Thus, if the ambient temperature is less than 18° C, a 1° C decrease will correspond to one additional heating degree day, while if the ambient temperature is greater than 18° C, a 1° C decrease will correspond to no change in the number of heating degree days.³⁵

Analogously, the concept of a cooling degree day (CDD_t) can be used to measure the magnitude by which ambient temperature is above the specified threshold. Thus, if the ambient temperature is greater than 18° C, a 1° C increase will correspond to one additional cooling degree day, while if the ambient temperature is less than 18° C, a 1° C increase will correspond to no change in the number of cooling degree days.³⁶

Monthly measures of HDD and CDD can be computed by summing the relevant daily HDDs and CDDs. It is expected that demand will be increasing in both measures. However, there is no reason to believe that the marginal effect of a one unit change of HDD will be the same as the marginal effect of a one unit change of CDD. Therefore, the two measures both appear independently in the demand equation.

Finally, consumption of electricity in Ontario is expected to be sensitive to the state of the macro economy in Canada and beyond. A broad measure of electricity-intensive economic activity is included in the model to control for this aspect of demand. The control variable adopted is the Institute for Supply Management's (ISM) Manufacturing Supplier's Delivery Index. This index measures deliveries of manufactured goods by producers located in the United States. To eliminate a potential endogeneity problem

³⁴ The first over-the-counter weather derivatives, based on this concept, were introduced in 1997. Various related weather futures and options on weather futures have been exchanged on the Chicago Mercantile Exchange since September 1999. For additional detail, see chapter 20 of Hull (2002).

³⁵ A 1° C decrease of ambient temperature corresponds to a fractional HDD if the initial temperature is less than 19° C.

³⁶ Analogously for CDD—see the previous footnote.

between this variable and Ontario-based demand, a one-month lag (M_{t-1}) is used in place of contemporaneous delivery index in the model.³⁷

Thus, the specification of Ontario-based demand equation used in the model is

$$q_t^d = \alpha_0 + \alpha_1(p_t + g_t) + \alpha_2HDD_t + \alpha_3CDD_t + \alpha_4M_{t-1} + \varepsilon_{3t} \quad (\text{II-3})$$

3.2.2.2. Exports

In addition to Ontario-based demand, electricity exchanged in Ontario's wholesale market is also consumed outside the province (q_t^e). Such demand constitutes exports of electricity with respect to Ontario and is modelled separately from Ontario-based demand. The rationale for this choice is analogous to the treatment of imports. Exports of electricity from Ontario are endogenously determined within the model.

As with Ontario-based demand, exports are expected to be decreasing in the wholesale market clearing price (p_t). Given that arbitrage is a critical aspect of the nature of inter-jurisdictional trade, whereas Ontario-based demand is determined by local economic

³⁷ Many alternative control variables exist that are sensitive to the state of the macro economy. For instance, the ISM also publishes an index called the Purchasing Managers' Index. This index is based on data broader in nature than deliveries (and, therefore, the deliveries index). However, since electricity usage is relatively more important to manufacturers than to other commercial firms, the deliveries index is a broad measure of economic activity that is particularly important to the electricity industry. Other potential alternative control variables considered include direct measures of the amount of manufacturing output (in Ontario, Canada, and the United States, or beyond) or manufacturing capacity utilisation, at sector, subsector, industry group, and industry levels as defined by the North American Industry Classification System (NAICS). Use of manufacturing sector data yields generally similar results, suggesting a degree of robustness to the particular choice made. Use of the less aggregated measures of manufacturing yielded varying results. This is likely a result of industry-specific effects. For instance, data regarding the transportation equipment manufacturing subsector (NAICS 336) and its nested industry groups and industries can be significantly impacted by planned shutdowns (say, for annual maintenance) and various other idiosyncratic effects such as strikes that are not meaningful factors relevant to outcomes in Ontario's electricity market. Industry-level analysis would be required to appropriately handle these issues. This is beyond the scope of the analysis undertaken in this thesis. Aside from its broad-based nature, the price index used was chosen because it is a long-established measure of manufacturing activity, having first been calculated in 1948. For a detailed discussion of the price index, including its usefulness as an indicator of manufacturing-sector activity, see Koenig (2002).

and environmental conditions in addition to the price, export demand is expected to be relatively more price elastic. With data measured in levels and not logs, this feature does need not imply anything meaningful about the magnitude of the coefficient associated with price relative to its equivalent in the Ontario-based demand equation. Note that in the (base-) case described above, it is the wholesale market price alone—and not the wholesale market price plus global adjustment as in Ontario-based demand—that is relevant to exports. The reason is that exports of electricity from Ontario are not charged global adjustment.

Exports are also expected to be dependent on contemporaneous market conditions in neighbouring jurisdictions. The quantity of electricity consumed in New York state (called the New York integrated load and denoted (NY_L_t)) is used as a proxy of market conditions beyond Ontario. It is expected that, *ceteris paribus*, higher levels of electricity consumption in New York will result in higher levels of demand for exports of electricity from Ontario.

The dummy variable discussed in relation to imports concerning linked-wheel transactions is included in the specification of the export equation based on an analogous rationale.

Thus, the specification of the export equation used in the model is

$$q_t^e = \beta_0 + \beta_1 p_t + \beta_2 NY_L_t + \beta_3 linked_t + \varepsilon_{4t} \quad (II-4)$$

3.2.3. The regulator's budget constraint

The regulator's operations began on 1 January 2005. Its purpose and objectives, along with other details, were described above. This section describes the budget constraint that binds on the regulator, which ensures that the costs incurred by the regulator in its

activities are recovered from (certain) electricity consumers through the global adjustment mechanism.

3.2.3.1. Revenues

The regulator collects revenue by levying the GA fee (g_t) on Ontario-based demand (q_t^d). Regulator revenue is the product of these two variables.

During the period from market opening to 31 December 2004, before the regulator existed, global adjustment was not levied, *i.e.*, $g_t = 0$, and consequently no revenues were obtained. This is accounted for in the modelling process.

The structure of the GA allocation mechanism was changed effective 1 January 2011. As a result of the change two classes of Ontario-based consumers arose: class A and class B. This issue is considered further in Appendix II-A, but is ignored in the modelling process for two reasons. First, the vast majority of Ontario-based consumers (based on quantity demanded) are expected to be class B consumers for whom global adjustment will be calculated and levied in an unchanged manner, *i.e.*, as a specific rate (g_t). Second, the new policy regime was only in place for the final six months/ observations of the sample period and consumers were just beginning to adapt thereto.

Thus, the regulator's revenues are

$$Rev_t = g_t * q_t^d \tag{II-5}$$

The discussion will return to the specification of equation (II-5) in relation to the counterfactual policies. In particular, under the counterfactual policy in which GA is applied to exports, it will be altered.

3.2.3.2. Expenses

As described in section 3.2.1.1 and Appendix II-B, significant expenses related to contractually specified out-of-market top-up payments to certain electricity generators are borne by the regulator. The regulator also bears significant expenses associated with a programme of conservation activities.

The equation for regulator expenses, reproduced from Appendix II-B, is

$$\begin{aligned} Exp_t = & q_t^{wind} * (p_c^{wind} - P_t) + q_t^{solar} * solar_capacity * (p_c^{solar} - P_t) \\ & + q_t^{nugs} * (p_c^{nugs} - P_t) + q_t^{nuclear} * (p_c^{nuclear} - P_t) + q_t^{base_hydro} * (p_c^{base_hydro} - P_t) \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (II-6)$$

This equation calibrated as described in Appendix II-B is

$$\begin{aligned} Exp_t = & q_t^{wind} * (135 - P_t) + q_t^{solar} * 0.19 * (420 - P_t) \\ & + 1577 * (75 - P_t) + q_t^{nuclear} * (55 - P_t) + 1900 * (33 - P_t) \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (II-7)$$

Note that the specification outlined in equations (II-6) and (II-7) does not guarantee or require that out-of-market top-up payments be positive transfers of funds from the regulator to generators. If the wholesale market clearing price was high enough, elements of the regulator's expenses could be negative, *i.e.*, the top-up can act as a claw-back mechanism.

In the period before the regulator existed—from market opening to 31 December 2004—it obviously incurred no expenses requiring recovery. This period corresponds to the period during which global adjustment was not levied as described in the immediately

preceding section.

The structure of regulator expenses was not altered by the global adjustment reforms of 2010, as described in Appendix II-A.

3.2.3.3. Budget balance

The regulator is required to balance its budget, *i.e.*, it must raise the same amount of revenue by choice of the global adjustment rate as it incurred as expenses carrying out its various activities. Therefore, equations (II-5) and (II-6) or, equivalently, equations (II-5) and (II-7), must be equal. Thus

$$Rev_t = Exp_t$$

Substitution yields

$$\begin{aligned} g_t * q_t^d = & q_t^{wind} * (p_c^{wind} - P_t) + q_t^{solar} * solar_capacity * (p_c^{solar} - P_t) \\ & + q_t^{nugs} * (p_c^{nugs} - P_t) + q_t^{nuclear} * (p_c^{nuclear} - P_t) \\ & + q_t^{base_hydro} * (p_c^{base_hydro} - P_t) \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (II-8)$$

This is the equation that endogenises the GA rate. If the regulator's expenses are positive in aggregate then the GA rate is positive, that is, GA collects revenue from the specified set of consumers. Alternatively, if the regulator's expenses are negative in aggregate the GA rate is negative, that is, GA returns revenue to the specified set of consumers.

3.2.4. Equilibrium

For the wholesale electricity market to clear, quantity supplied must equal quantity

demanded. Conceptually, this means that Ontario-based supply plus imports must equal Ontario-based demand plus exports. However, this condition must be adjusted to account for transmission losses associated with the transmission of electricity.

When electricity is transmitted across a transmission system, a fraction of what is dispatched does not arrive at its destination. For instance, some of the dispatched electricity is converted to heat and lost. The dispatched electricity that is lost is referred to as line losses and can be thought of as the transportation cost associated with transmitting electricity from its point of generation to its point of consumption. Line losses—denoted as $0 < L < 1$ —are modelled as a constant fraction through time; a process sometimes referred to as iceberg transportation costs in other contexts. In particular, $L = 0.025$ is assumed, *i.e.*, line losses constitute 2.5% of dispatched electricity.

Thus, the specification of the market clearing equilibrium condition in quantities in the model is

$$q_t^d + q_t^e = (1 - L) * (q_t^s + q_t^i) \quad (\text{II-9})$$

4. Data and literature review

This section discusses the data used in the electricity market model estimated in this chapter and summarises a few empirical findings regarding price elasticities that are reported in existing literature.

4.1. Data

This study uses monthly data observed over a 110 month period from May 2002 to June 2011, inclusive.

The six endogenously determined variables—wholesale market clearing price, global adjustment, Ontario-based supply, imports, Ontario-based demand, and exports—as

well as the so-called all-in price, that is, the sum of the wholesale market clearing price and GA, are plotted in Figures II-3, II-4, and II-5. Summary statistics for these variables are reported in Table II-1. Summary statistics for the exogenous variables used in the econometric model are reported in Table II-2.

The two market-determined prices—the wholesale market clearing price and the GA rate—are illustrated in Figure II-3. It is apparent that at the regulator’s origin the GA was near zero and subsequently somewhat negative. This is consistent with the regulator’s generation procurement programme just being initiated.³⁸ Over time, as the magnitude of regulatory activity increased, the costs funded by the GA increased. The creation of the GA appears to have stabilised the all-in price (which, before the creation of the GA was the wholesale market price itself). The seasonal character of Ontario-based demand—with local peaks in both the summer and the winter, with spring and fall shoulder seasons, all of which is largely driven by average air temperature—is illustrated in Figure II-4. Figure II-4 also reveals the magnitude of net exports, which is the difference between Ontario-based supply and demand.

The individual components of net exports—imports and exports—are illustrated in Figure II-5. Over the 110 month study period, Ontario was generally a net exporter, with average net exports averaging approximately 350 MWh per hour. During the period shortly after market opening, Ontario was, on average, a net importer of electricity. During the last 24 months of the study period net exports averaged approximately 1,070 MWh per hour. The long-run trend towards exporting more, importing less, and consequently having higher net exports is clear from these data as well as Figure II-5. This trend is driven, at least partially, by the general decline of the wholesale market clearing price—which is the price paid (received) by (for) exports

³⁸ Other regulatory programmes, such as various conservation initiatives, began simultaneously. See Appendix II-B for additional detail.

(imports).³⁹ It is this long-run trend that motivates interest in the counterfactual policy under which the GA rate would be applied to exports.

The data regarding New York integrated load results from a market process similar—though different in many important respects—to Ontario’s for the full duration of the study period. Note that the opening of New York’s wholesale electricity market pre-dates Ontario’s.

Electricity market data were obtained from the Independent Electricity System Operator (IESO), Ontario Power Authority (OPA), and Ontario Energy Board (OEB). Canadian

Figure II-3: Wholesale market price, global adjustment, and the all-in price

³⁹ This statement ignores the role of intertie congestion, which when present creates a wedge between the internal and external Ontario electricity prices. This issue is the subject of the companion chapter on Ontario’s market for financial transmission rights (FTR). The full impact of the regulator’s activities depends on outcomes in that market and is critically dependent on whether FTR auction markets are efficient, *i.e.*, characterised by forward market unbiasedness or not.

Figure II-4: Ontario-based demand and supply

Figure II-5: Exports and imports

Table II-1: Summary statistics of endogenous variables

Variable	Units	Mean	Std. Dev.	Minimum	Maximum
q_t^d	MWh per hour	16,611.5	1,242.8	13,766.0	19,352.8
q_t^s	MWh per hour	17,483.2	1,264.9	14,984.0	20,537.0
q_t^e	MWh per hour	1,381.3	682.2	49.0	3,512.0
q_t^i	MWh per hour	935.8	416.1	216.0	2,154.0
p_t	Dollars per MWh	49.01	15.32	19.60	98.10
g_t	Dollars per MWh	9.43	15.68	-21.37	50.05
$p_t + g_t$	Dollars per MWh	58.44	9.49	30.07	88.17

Table II-2: Summary statistics of exogenous variables

Variable	Units	Mean	Std. Dev.	Minimum	Maximum
HDD_t	Degrees Celsius	10.20	8.78	0.00	27.39
CDD_t	Degrees Celsius	1.01	1.62	0.00	6.21
M_{t-1}	Unit int. index	55.91	7.93	26.30	70.00
NY_L_t	MWh per hour	16,494.1	1,515.7	14,223.4	20,743.5
$fuel_t$	Dollars	4.23	1.06	2.60	7.59
$baseload_t$	MWh per hour	14,707.6	1,427.1	9,870.0	17,555.5

weather data are from Environment Canada. Natural gas and coal prices are from the United States Energy Information Administration (US EIA), converted to Canadian currency using the last exchange rate observation for the month, as recorded by the Bank of Canada. The Institute for Supply Management's Manufacturing Supplier Delivery Index was obtained from the Federal Reserve Economic Data (FRED) database maintained by the Federal Reserve Bank of St. Louis.

4.2. Previous estimates of price elasticities

There is a voluminous literature associated with the analysis of electricity markets. While much of this work was motivated by the desire to undertake policy analysis, since this chapter is focused on the development of a model of Ontario's electricity

market in its own right—with policy analysis to follow in chapter III—a small subset of this literature is considered here. In particular, attention here is paid to the results of previous empirical investigations of the price elasticities of the various components of the market. It is to these investigations that the empirical results derived later in this chapter can be compared.

Estimation of the price elasticity of demand for electricity has been carried out on many occasions. Taylor (1975) emphasised the importance of distinguishing between the short and long run in the context of electricity demand. Given the focus of this chapter, attention here is paid to short-run analyses.

One early analysis of electricity demand was reported by Houthakker (1951), in which data for the years 1937 and 1938 from 42 municipalities in the United Kingdom were analysed. The price elasticity of demand was reported to be -0.9. Subsequent analysis by Houthakker and Taylor (1970) estimated the price elasticity on a state-by-state basis in the United States, with results ranging from -1.58 to -0.05 and an average in the inelastic range.⁴⁰ Additional analyses in the early literature include Baxter and Rees (1968), Wilson (1971), Anderson (1973), Griffin (1974), Houthakker, Verleger, and Sheehan (1973), and Mount, Taylor, and Tyrrell (1973). By the time of Taylor (1975), it had become a stylised fact that electricity demand is inelastic, and more so in the short run than in the long run.

Many additional analyses of electricity demand have been conducted since the 1970s. A number of surveys of this literature have also been conducted. Among these surveys are Bohi and Zimmerman (1984), Espey and Espey (2004), Reiss and White (2005), and Lijesen (2007). Estimates of price elasticity in these surveys vary considerably, though most are within the range -0.4 to -0.1, with an average of -0.2.

⁴⁰ Alaska and Hawaii were excluded.

There is a significant and growing literature associated with the estimation of price elasticity of supply, especially in relation to analysis of renewable portfolio standards—policy instruments intended to incentivise entrance and utilisation of renewable generation capacity into electricity markets. For an example of this literature, see Johnson (2010). However, the characteristics of electricity supply in a given jurisdiction are at least somewhat dependent upon underlying geographic characteristics, such as the endowment of hydroelectric resources. Compared to Ontario, jurisdictions such as Quebec, British Columbia, and Norway are endowed with relatively significant hydroelectric resources, while jurisdictions such as Alberta, Texas, and Australia lack them almost completely. As a result, estimates of price elasticity of supply are less comparable across space than are estimates of price elasticity of demand.

Inter-jurisdictional trade of electricity has been much less widely studied. The basic rationale for such trade is to arbitrage spatial price differences, with electricity flowing from low-price to high-price jurisdictions. Borenstein, Bushnell, and Wolak (2002) explicitly accounts for the role of imports in its study of the Californian electricity market over the years 1998 to 2000, but does not explicitly undertake measurement of their price responsiveness. Mansur (2003) estimates the price elasticity of net imports to range between 0.79 and 4.20 depending on the time of day, for the Pennsylvania-New Jersey-Maryland (PJM) market. IESO (2008) estimates the price elasticity of exports from Ontario to New York to range between -5.65 and -2.79 depending on the time of day, with an average of -4.67.

Taken together, the literature suggests that demand is substantially less price responsive than is inter-jurisdictional trade.

5. Estimation and results

Each estimable equation is specified as a linear relationship of the variables as discussed

above. Months are indexed with the subscript t . All 110 observations (months) are used in the estimation of each estimable equation.

5.1. Estimation technique and estimates

Each of the four estimable equations has one regressor—the relevant price—that is endogenously-determined. The equations, therefore, cannot be consistently estimated with the standard ordinary least squares estimator. Instead, the four estimable equations are estimated by a generalised method of moments instrumental variables (GMM IV) estimator with heteroskedasticity and autocorrelation consistent standard errors. The instruments used in each equation are the excluded exogenous variables that appear in the other estimable equations of the system.

Econometric results associated with the estimation of equations (II-1), (II-2), (II-3), and (II-4) are reported in the four panels, A, B, C, and D, respectively, of Table II-3. The F-statistic associated with the appropriate first-stage regression and the J-test of over-identifying restrictions is also reported in the various panels of Table II-3.

These results were generated by use of Stata/SE 11.0 for Windows.

Table II-3: Panel A: Estimation of Ontario-based Supply Equation

Variable	Coefficient	z-statistic	p-value
p_t	110.14	30.11	0.000
$fuel_t$	-689.10	-10.53	0.000
$baseload_t$	1.023	35.19	0.000
Constant	-68.62	-0.15	0.881
First-stage F-statistic (with p-value)		129.00	(0.0000)
J- statistic (with p-value)		1.6674	(0.8930)

Table II-3: Panel B: Estimation of Import Equation

Variable	Coefficient	z-statistic	p-value
p_t	20.29	17.52	0.000
NY_L_t	-0.044	-5.27	0.000
$linked_t$	723.19	22.12	0.000
Constant	612.97	6.14	0.000
First-stage F-statistic (with p-value)		200.43	(0.0000)
J- statistic (with p-value)		1.6508	(0.8950)

Table II-3: Panel C: Estimation of Ontario-based Demand Equation

Variable	Coefficient	z-statistic	p-value
$p_t + g_t$	-84.55	-8.94	0.000
HDD_t	190.69	46.82	0.000
CDD_t	907.54	60.99	0.000
M_{t-1}	19.39	7.27	0.000
Constant	17,607.3	34.94	0.000
First-stage F-statistic (with p-value)		63.02	(0.0000)
J- statistic (with p-value)		1.7740	(0.7772)

Table II-3: Panel D: Estimation of Export Equation

Variable	Coefficient	z-statistic	p-value
p_t	-21.71	-12.63	0.000
NY_L_t	0.122	14.05	0.000
$linked_t$	1717.42	33.13	0.000
Constant	325.67	2.84	0.004
First-stage F-statistic (with p-value)		200.43	(0.0000)
J- statistic (with p-value)		1.7522	(0.8823)

5.2. Discussion

Before turning to a discussion of the coefficient estimates, the relevance and validity of the instruments used are considered. There are two basic requirements that an instrumental variable must satisfy: it must be correlated with the endogenous variable

and orthogonal to the (unobservable) error process. The first-stage F-statistic and the J-statistic can be used to consider these requirements. Each estimable equation is considered separately.

The first-stage F-statistic provides a useful rule-of-thumb regarding the assessment of the strength of the instruments employed, that is, whether the instruments used are meaningfully correlated with the endogenous variable—of which there is one in each estimable equation. Weak instruments result, at best, in misleading inference. Indeed, sufficiently weak instruments may function no better than randomly generated instruments. This point was made by, for instance, Bound, Jaeger, and Baker (1995) regarding Angrist and Krueger's (1991) study of returns to education and is an issue that must be considered here. Stock, Wright, and Yogo's (2002) discussion of weak instruments in the context of GMM concludes that when the first-stage F-statistic is less than 10 that it is prudent to use an estimation method fully-robust to instrument weakness instead of GMM. However, of the four estimable equations considered here, the smallest first-stage F-statistic—approximately 63, from Table II-3 Panel C—is well above the threshold referred to by Stock, Wright, and Yogo (2002).

Hansen's (1982) J-statistic can be used to assess an instrument's independence from the (unobservable) error process. This test can be used if an equation is overidentified—which is true of each of the estimable equations. The null hypothesis is jointly that the instruments are orthogonal to the error and the model is correctly specified. A rejection of the null hypothesis implies that either the instruments do not satisfy the orthogonality condition or the model was misspecified. Such a result implies that either the instruments are not exogenous or were wrongly excluded from the regression. As reported in the various panels of Table II-3, the null hypothesis is not rejected in relation to any of the four estimable equations.

These results, taken together, afford confidence in both the model specifications and instruments chosen.

With respect to the coefficient estimates, with the exception of the constant in the Ontario-based supply equation, all coefficient estimates differ statistically from zero in the directions described in section 3.

The coefficient estimate associated with the wholesale market clearing price in the equations for Ontario-based supply and imports are both positive and statistically significant. In other words, each of these curves is upward-sloping. In particular, *ceteris paribus*, a \$1 per MWh increase of the wholesale market clearing price corresponds to a 110 MWh per hour increase in Ontario-based supply and a 20 MWh per hour increase in imports. On the other hand, the coefficient estimates associated with the price paid by consumers—the wholesale market clearing price plus global adjustment in the case of Ontario-based demand, and the wholesale market clearing price alone in the case of exports—are both negative and statistically significant. In other words, each of these curves is downward-sloping. In particular, *ceteris paribus*, a \$1 per MWh increase of the relevant price paid by consumers corresponds to an 85 MWh per hour decrease in Ontario-based demand and a 22 MWh per hour decrease in exports.

With respect to the Ontario-based supply equation, the coefficient estimate associated with the fuel price index—constructed using the coal and natural gas prices—is negative and statistically significant. This indicates that increased costs of generation have a negative marginal effect on market supply. The coefficient estimate associated with baseload generation is positive and statistically significant. This indicates that increased generation from generally non-price responsive generators increases supply.

With respect to the Ontario-based demand equation, the coefficient estimates associated with the temperature variables—HDD and CDD—are positive and statistically

significant. This indicates that demand is increasing in the extent to which ambient temperature deviates from 18° C, the baseline adopted in section 3. The relationship between these two variables, as well as the coefficient estimates themselves, is discussed in further detail below. The coefficient estimate associated with the manufacturing activity index is also positive and statistically significant. This indicates that demand is greater when there is greater manufacturing activity.

With respect to the imports equation, the coefficient estimate associated with the New York integrated load variable is negative and statistically significant. This indicates that greater consumption of electricity in New York results in fewer imports to Ontario, a result due to less electricity being available for export from New York at any given price when New York demand is relatively high. The coefficient associated with the dummy variable related to the period—the first seven months of 2008—in which the volume of linked-wheel transactions was notably high is both positive and statistically significant. The point estimate indicates that the average volume of extraordinary linked-wheel transactions scheduled either through Ontario or ending in Ontario (thus, import-only) was approximately 723 MWh per hour during the period. This represents approximately 44% of the average 1655 MWh per hour of imports observed during the seven-month period.

With respect to the exports equation, the coefficient estimate associated with the New York integrated load variable is positive and statistically significant. This indicates that greater consumption of electricity in New York results in greater exports from Ontario, a result due to more electricity being demanded in New York at any given price when New York consumption is relatively high. This effect is, as expected, opposite that found in relation to imports. The coefficient associated with the dummy variable related to extraordinary levels of linked-wheel transactions is both positive and statistically significant. The point estimate indicates that the average volume of

extraordinary linked-wheel transactions scheduled either through Ontario or beginning in Ontario (thus, export-only) was approximately 1,718 MWh per hour during the period. This represents approximately 58% of the average 2,974 MWh per hour of exports observed during the seven-month period.

It was noted above that the coefficient estimates associated with the temperature variables—HDD and CDD—in the Ontario-based demand equation were both positive and statistically significant. The coefficient estimates are 190.69 and 907.54, respectively. These values indicate that a 1° C decrease in the ambient temperature below a threshold of 18° C, that is, a one-unit increase of the heating degree day (HDD), increases average demand by approximately 191 MWh per hour. Similarly, a 1° C increase in the ambient above a threshold of 18° C, that is, a one-unit increase of the cooling degree day (CDD), increases average demand by approximately 908 MWh per hour. (Recall that the data are monthly averages.) In other words, demand increases by an average of 191 MWh per hour when ambient temperature falls by 1° C if it is relatively cold outside. Likewise, demand increases by an average of 908 MWh per hour when ambient temperature increases by 1° C if it is relatively warm outside. This reflects, to some extent, the use of electricity to power space-heating and -cooling equipment.

It is notable that the marginal effect on Ontario-based demand due to a change in ambient temperature seems to depend on the level of the ambient temperature. That is, the marginal effects associated with the HDD and CDD variables are different.

Whether this apparent difference is statistically significant in nature can be assessed with a chi-square test. The test results⁴¹ indicate that it is indeed the case that the

⁴¹ The null hypothesis $H_0: \alpha_2 = \alpha_3$ is tested against the alternative hypothesis $H_0: \alpha_2 \neq \alpha_3$. The test-statistic is distributed as a chi-square variable with one degree of freedom. The calculated test-statistic value is 2,315.92, with a related p-value of 0.0000. As a result, the null hypothesis can be rejected.

marginal effects differ, with the marginal effect of a 1° C increase in the ambient temperature when it is relatively warm outside being approximately five times greater than the marginal effect of a 1° C decrease in the ambient temperature when it is relatively cold outside. The relatively large impact of a change of ambient temperature when it is relatively warm outside reflects the lack of substitutes to electricity that are available to power space-cooling equipment compared to space-heating equipment. In particular, space-cooling air conditioners are generally powered with electricity, while space-heating heaters can be powered with electricity as well as fossil fuels such as natural gas and propane. Indeed, according to data from the Office of Energy Efficiency, Natural Resources Canada, electricity powered between 13.1% and 15.4 % of space-heating equipment in Ontario during the years 2003 through 2009, inclusive (NRC, 2011, Table 5).

5.3. Price elasticity estimates

The econometric results can be used to estimate the price elasticities associated with each of the four endogenously-determined quantities. The absolute values of these estimates are reported in Table II-4.

The point estimate of price elasticity of demand is 0.301. This falls within the range of estimates reported in the existing literature, as summarised in section 4.2. As discussed in section 4.2, estimates of price elasticity of supply are not directly comparable across jurisdictions.

The point estimates of price elasticity of imports and exports are 1.103 and 0.976, respectively. Each of these estimates fall within the range of estimates of price elasticity of net imports reported by Mansur (2003), as discussed in section 4.2. This suggests that the character of inter-jurisdictional trade between Ontario and its neighbours is not fundamentally different than that of California and its neighbours.

Table II-4: Price Elasticity Estimates⁴²

Equation	Estimate	Std. Dev.
(1) Ontario-based supply	0.307	0.082
(2) Imports	1.103	0.158
(3) Ontario-based demand	0.301	0.064
(4) Exports	0.976	0.870

These data report that import supply is greater than three times ($1.103/0.307 = 3.59$) as price elastic as Ontario-based supply and that export demand is also greater than three times ($0.976/0.301 = 3.25$) as price elastic as Ontario-based demand. Thus, inter-jurisdictional trade is far more price responsive than Ontario production and consumption, a result consistent with the view that inter-jurisdictional trade is driven by arbitrage. It is also notable that Ontario-based supply is approximately as price elastic as Ontario-based demand (0.307 and 0.301, respectively). These results are particularly important in relation to the counterfactual policy discussion regarding the application of global adjustment to exports in chapter III.

6. Fitted base case

This section undertakes the fitting of the market equilibrium using the system of equations and econometric estimates reported in previous sections. This is the so-called base case. Section 6.1 describes the process by which the base case equilibrium is

⁴² The price elasticity of Ontario-based supply, ε_t^s , was calculated for each month as

$$\varepsilon_t^s = \frac{\gamma_1 p_t}{q_t^s(p_t)}$$

where the denominator is equation (1)—the Ontario-based supply equation—evaluated at the *observed* wholesale market clearing price. The mean of this series, ε^s , is reported in Table II-4. The other price elasticities were calculated analogously, noting that in the case of Ontario-based demand the relevant price in the wholesale market clearing price plus the global adjustment rate.

Elasticities are reported in absolute value terms.

constructed. Section 6.2 reports results related to the base case, while section 6.3 provides related discussion.

6.1. Procedure

This section provides an explanation of how the four estimable equations of the model—Ontario-based supply, imports, Ontario-based demand, and exports—are combined with the two identities of the model—the quantity equilibrium condition and the regulator’s budget constraint—to determine equilibrium. This explanation is accompanied by a technical description of the analytical solution to the system of equations in Appendix II-C.

The specification for Ontario-based supply adopted in section 3.2.1.1 is

$$q_t^S = \gamma_0 + \gamma_1 p_t + \gamma_2 \text{fuel}_t + \gamma_3 \text{baseload}_t + \varepsilon_{1t} \quad (\text{II-1})$$

Given that the exogenous explanatory variables—the fuel price index and the amount of baseload generation—vary on a month-to-month basis, the component of the Ontario-based supply equation that is independent of the wholesale market clearing price can be represented, for month t , as

$$\gamma_{0t} = \gamma_0 + \gamma_2 \text{fuel}_t + \gamma_3 \text{baseload}_t \quad (\text{II-10})$$

Substitution of equation (II-10) into equation (II-1) yields

$$q_t^S = \gamma_{0t} + \gamma_1 p_t + \varepsilon_{1t} \quad (\text{II-11})$$

Econometric estimates of the coefficients in equation (II-1) were reported in section 5.1. These estimates, in addition to the fuel price index and baseload generation data series, can be used to construct equations (II-10) and (II-11), yielding a fitted equation for Ontario-based supply

Figure II-6: Base case Ontario-based supply

$$\hat{q}_t^s = \hat{y}_{ot} + \hat{y}_1 p_t \quad (\text{II-12})$$

This equation, referred to as base case Ontario-based supply in order to facilitate discussion of the policy counterfactuals, is illustrated in Figure II-6. The graphical characterisation of equation (II-12), the function's positive slope and negative vertical intercept in particular, correspond with the discussion provided in section 3.2.1.1 and the econometric results reported in section 5.1.

The specification for imports adopted in section 3.2.1.2 is

$$q_t^i = \delta_0 + \delta_1 p_t + \delta_2 NY_L_t + \delta_3 linked_t + \varepsilon_{2t} \quad (II-2)$$

Similarly to Ontario-based supply, define

$$\delta_{0t} = \delta_0 + \delta_2 NY_L_t \quad (II-13)$$

$$q_t^i = \delta_{0t} + \delta_1 p_t + \varepsilon_{2t} \quad (II-14)$$

and

$$\hat{q}_t^i = \hat{\delta}_{0t} + \hat{\delta}_1 p_t \quad (II-15)$$

Equation (II-15), referred to as base case import supply in order to facilitate discussion of the policy counterfactuals, is illustrated in Figure II-7. The graphical characterisation of equation (II-12), the function's positive slope and positive vertical intercept in particular, correspond with the discussion provided in section 3.2.1.2 and the econometric results reported in section 6.1. In addition, since (gross) imports must be non-negative, at prices below $(-\hat{\delta}_{0t}/\hat{\delta}_1)$ import supply is zero.

Figure II-7: Base case import supply

Aggregate market supply is the sum of Ontario-based supply and imports. Using the econometric results reported in section 6.1., it can be written as the sum of equations (II-12) and (II-15). That is

$$\hat{Q}_t^{AS} = \hat{q}_t^s + \hat{q}_t^i = \hat{\gamma}_{0t} + \hat{\delta}_{0t} + (\hat{\delta}_1 + \hat{\gamma}_1)p_t \quad (\text{II-16})$$

Equation (II-16), referred to as base case aggregate supply, is illustrated in Figure II-8.

Figure II-8: Base case aggregate supply

Base case aggregate demand is the solid line. The graphical characterisation of equation (II-16), the function's positive slope and negative vertical intercept in particular, correspond with the discussion provided in sections 3.2.1.1 and 3.2.1.2 as well as the econometric results reported in section 6.1.

As noted above in the description of base case import supply, at prices below $(-\hat{\delta}_{0t}/\hat{\delta}_1)$ import supply is zero.⁴³ In other words, at prices below $(-\hat{\delta}_{0t}/\hat{\delta}_1)$ aggregate base case supply is comprised of Ontario-based supply only. With respect to Figure II-8, this feature corresponds to base case aggregate supply being the dash-dot line at prices below $(-\hat{\delta}_{0t}/\hat{\delta}_1)$. This feature is not reflected in the mathematical representation of base case aggregate supply. This would be problematic if the wholesale market clearing price in any month t was ever less than $(-\hat{\delta}_{0t}/\hat{\delta}_1)$. This turns out not to be the case. The reason is that the fitted value of (gross) imports would be negative, thereby violating the non-negativity assumption.⁴⁴

The specification for Ontario-based demand adopted in section 3.2.1.3 is

$$q_t^d = \alpha_0 + \alpha_1(p_t + g_t) + \alpha_2HDD_t + \alpha_3CDD_t + \alpha_4M_{t-1} + \varepsilon_{3t} \quad (\text{II-3})$$

Similarly to Ontario-based supply and imports, define

$$\alpha_{0t} = \alpha_0 + \alpha_2HDD_t + \alpha_3CDD_t + \alpha_4M_{t-1} \quad (\text{II-17})$$

$$\hat{q}_t^d = \alpha_{0t} + \alpha_1(p_t + g_t) + \varepsilon_{3t} \quad (\text{II-18})$$

and

$$\hat{q}_t^d = \hat{\alpha}_{0t} + \hat{\alpha}_1(p_t + g_t) \quad (\text{II-19})$$

⁴³ Note that $(-\hat{\delta}_{0t}/\hat{\delta}_1)$ varies on a month-to-month basis.

⁴⁴ If the wholesale market clearing price was ever less than $(-\hat{\delta}_{0t}/\hat{\delta}_1)$ in a given month, the simulation procedure would have to explicitly recognise this outcome and set (gross) imports to zero. As noted in the main text, this turns out not to be necessary.

Equation (II-19), referred to as base case Ontario-based demand, is illustrated in Figure II-9. The graphical characterisation of equation (II-19), the function's negative slope and positive intercept in particular, correspond with the discussion provided in section 3.2.1.3 and the econometric results reported in section 6.1.

The critically important feature of Figure II-9 is its illustration of the impact of the GA rate on observed demand. The gross-of-GA demand curve, based in principle on

Figure II-9: Base case Ontario-based demand

willingness-to-pay, is the dashed line while the net-of-GA demand curve, which is observed in the wholesale electricity market, is the solid line, both of which possess the same slope. The vertical distance between the two lines is the GA rate, meaning that the slopes are the same. The particular situation illustrated in Figure II-9 presumes a positive GA rate, that is, a GA rate that constitutes a charge to Ontario-based consumers of electricity. This is not the only possible case. As reported in Table II-1 in section 5, throughout its existence the GA rate has been both positive and negative. A negative GA rate would constitute a rebate to Ontario-based consumers and would be associated with the net-of-GA demand curve being located above the gross-of-GA demand curve in a diagram analogous to Figure II-9. In any event, the equilibrium GA rate is endogenously determined within the electricity market.

The specification for exports adopted in section 3.2.1.4 is

$$q_t^e = \beta_0 + \beta_1 p_t + \beta_2 NY_L_t + \beta_3 linked_t + \varepsilon_{4t} \quad (II-4)$$

Similarly to the other estimable equations, define

$$\beta_{0t} = \beta_0 + \beta_2 NY_L_t \quad (II-20)$$

Figure II-10: Base case export demand

$$q_t^e = \beta_{0t} + \beta_1 p_t + \varepsilon_{4t} \quad (\text{II-21})$$

and

$$\hat{q}_t^e = \hat{\beta}_{0t} + \hat{\beta}_1 p_t \quad (\text{II-22})$$

Figure II-11: Base case market demand

Equation (II-22), referred to as base case export demand, is illustrated in Figure II-10. The graphical characterisation of equation (II-22), the function's negative slope and positive intercept in particular, correspond with the discussion provided in section 3.2.1.4 and the econometric results reported in section 6.1. In addition, since (gross) exports must be non-negative, at prices in excess of $(-\hat{\beta}_{0t}/\hat{\beta}_1)$ export demand is zero. In other terms, $(-\hat{\beta}_{0t}/\hat{\beta}_1)$ is the choke price of export demand.

Aggregate market demand is the sum of Ontario-based demand and exports. Using the econometric results reported in section 6.1, it can be written as the sum of equations (II-19) and (II-22). That is

$$\hat{Q}_t^{AD} = \hat{q}_t^d + \hat{q}_t^e = \hat{\alpha}_{0t} + \hat{\beta}_{0t} + (\hat{\alpha}_1 + \hat{\beta}_1)p_t + \hat{\alpha}_1 g_t \quad (\text{II-23})$$

Equation (II-23), referred to as base case aggregate demand, is illustrated in Figure II-11. The graphical characterisation of equation (II-23), the function's negative slope and positive vertical intercept in particular, correspond with the discussion provided in sections 3.2.1.3 and 3.2.1.4 as well as the econometric results reported in section 6.1.

As noted above in the description of base case export demand, at prices in excess of $(-\hat{\beta}_{0t}/\hat{\beta}_1)$ export demand is zero. With respect to Figure II-11, this feature corresponds to the net-of-GA base case aggregate demand curve being the dash-dot line at prices in excess of $(-\hat{\beta}_{0t}/\hat{\beta}_1)$. This feature is not represented in the mathematical representation of base case aggregate demand. This would be problematic if the wholesale market clearing price plus the GA rate in any given month t was ever in excess of $(-\hat{\beta}_{0t}/\hat{\beta}_1)$. This turns out not to have been the case. The reason is that the fitted values of (gross) exports would be negative at such prices, thereby violating the non-negativity

assumption.⁴⁵

Market equilibrium is characterised by aggregate supply, equation (II-16), equaling aggregate demand, equation (II-23). In section 3.2.4, the wholesale market equilibrium was characterised by

$$q_t^d + q_t^e = (1 - \text{losses}) * (q_t^s + q_t^i) \quad (\text{II-9})$$

This equilibrium is illustrated in Figure II-12, which is a combination of Figures II-8 and II-11. The illustrated equilibrium ignores the issue of line losses—which generally results in observed aggregate supply being less than observed aggregate demand—as specified in equation (II-9).

The base case wholesale market clearing price is determined by the intersection—labelled point E—of base case aggregate supply with base case aggregate demand and is denoted p_t^* in Figure II-12. The illustrated equilibrium makes use of five of the six equations in the system: Ontario-based supply, imports, Ontario-based demand, exports, and the quantity equilibrium condition. This equilibrium depends, however, on the magnitude of g_t^* . Notwithstanding this, the GA rate is an endogenously determined variable as a result of the sixth equation of the system that is not illustrated in Figure II-12: the regulator’s budget constraint, equations (II-5), (II-7), and (II-8).

It is useful to consider the role of the regulator’s budget constraint in the determination of the wholesale market equilibrium. Suppose the GA rate in a given month is 0, *i.e.*, $g_t^* = 0$. As per equation (II-5), the regulator will raise no revenue. In this case, the gross-of-GA and net-of-GA demand curves are coincident. The wholesale market

⁴⁵ If the wholesale market clearing price was ever in excess of $(-\hat{\beta}_{0t}/\hat{\beta}_1)$ in a given month, the simulation procedure would have to explicitly recognise this outcome and set (gross) exports to zero. As noted in the main text, this turns out not to be necessary.

Figure II-12: Base case wholesale market equilibrium

would clear as illustrated in this section, thereby determining the wholesale market clearing price as well as the four endogenously determined quantities. This outcome is

an equilibrium if and only if the regulator's budget is balanced, that is, if equation (II-8) holds at equality. In this case, since the regulator generates no income, it cannot have an equilibrium if and only if the regulator's budget is balanced, that is, if equation (II-8) holds at equality. In this case, since the regulator generates no income, it cannot have net expenses, as per equation (II-7), that differ from 0.⁴⁶ If the regulator's budget constraint does not hold at equality, then it cannot be the case that $g_t^* = 0$.

The manner in which the regulator's budget constraint fails to hold is instructive with respect to whether the equilibrium GA rate is positive (a charge to Ontario-based consumers) or negative (a rebate to Ontario-based consumers). In particular, if the regulator's budget is in deficit when $g_t^* = 0$, then a (positive) GA rate must be charged to consumers in order to raise the required revenues and bring the budget into balance. Conversely, if the regulator's budget is in surplus when $g_t^* = 0$, then a (negative) GA rate must be rebated to consumers in order to dispense the negative expenses collected by the regulator under its supply procurement contracts and bring the budget into balance. Any GA rate that differs from zero will result in the gross-of-GA and net-of-GA demand curves necessarily being non-coincident. This more general situation is illustrated in Figure II-12. The lowest GA rate that clears the wholesale market and balances the regulator's budget constitutes the equilibrium GA rate.⁴⁷

As stated above, an analytical solution to this model is provided for in Appendix II-C.

⁴⁶ This does not mean that the regulator cannot provide out-of-market payments to any particular generator. Rather, it requires that the sum of all out-of-market payments—which may be negative—be zero. See Appendix II-B for further discussion.

⁴⁷ The regulator's budget constraint is quadratic in the GA rate. This can be seen from equation (II-5), where the regulator's revenue is written as the product of the GA rate and the quantity of Ontario-based demand, which is itself a function of the GA rate as per equation (II-3). As a result, there are potentially two unique, real solutions to the mathematical procedure that solves for the GA. The lowest GA rate is chosen so as to minimise the impact of the regulator on the market equilibrium.

6.2. Base case results

The fully-parameterised system—using the results reported in Table II-3—of six equations is solved for the base case values of each of the six endogenous variables as described above. This section reports the results of this simulation, along with a restatement of certain statistics regarding the observed data.

Table II-5 reports the mean and standard deviations of the observed and base case endogenous variables for all 110 months of the study period and the last 24 months only. Figure II-13 plots the observed and base case time series for the wholesale market clearing price over all 110 months. Figures II-14, II-15, and II-16 report comparable data in relation to the wholesale market clearing price, GA, all-in price, and four endogenous quantity variables, respectively.

The purpose of these data is to provide a descriptive-only sense of the performance of the system of equations. Formally, the fit of the system of equations can be assessed in relation to the quality of the instruments employed in estimation. As discussed in section 5, the instruments are of sufficiently high quality to proceed with estimation and inference.

Inspection of the data and figures presented above suggests that the fitted base case series approximate the observed data relatively well. Given that the fitted base case is definitionally endogenous with respect to the model, calculation of common goodness-of-fit measures generates spurious results.

Table II-5: Mean and standard deviation of observed and base case endogenous variables
All months and last 24 months

Variable	Case	All Months		Last 24 Months	
		Mean	Std. Dev.	Mean	Std. Dev.
q_t^s	Observed	17,483.2	1,264.9	17,161.4	1,282.7
	Base Case	17,570.2	1,129.6	17,583.2	1,182.9
q_t^i	Observed	935.8	416.1	624.8	226.8
	Base Case	949.0	306.3	655.8	195.9
q_t^d	Observed	16,611.5	1,242.8	15,689.5	1,110.6
	Base Case	16,685.5	1,168.4	16,263.8	1,303.0
q_t^e	Observed	1,381.3	682.2	1,693.9	422.7
	Base Case	1,370.7	459.6	1,519.2	217.1
p_t	Observed	49.01	15.32	33.32	7.40
	Base Case	49.83	11.91	37.46	11.05
g_t	Observed	9.42	15.68	33.35	9.65
	Base Case	7.71	12.77	24.85	11.38
$p_t + g_t$	Observed	58.44	9.49	66.67	4.21
	Base Case	57.54	5.09	62.31	1.87

Figure II-13: Observed and base case wholesale market price

Figure II-14: Observed and base case global adjustment

Figure II-15: Observed and base case all-in price

Figure II-16: Observed and base case equilibrium quantities

7. Conclusions

The purpose of this chapter is to formulate an analytical model of Ontario's electricity market for use in counterfactual policy analysis. To that end, a six-equation model was developed. The parameters of the estimable equations of this system were estimated using a generalised method of moments instrumental variables estimator. It was determined that the instruments chosen for use in estimation were of sufficient quality to proceed with further analysis.

The system of equations, having been fitted using these econometric results, was used to construct a base case equilibrium. This construction is a crucial component to the

process of counterfactual policy analysis. The reason is that the impact of any counterfactual policy under consideration is defined as the deviation of the resulting (counterfactual) equilibrium from the fitted base case. This is necessary so as to isolate the impact of the alternative policy being considered from errors in modelling historical data.

Counterfactual policy analysis is the focus of chapters III and IV.

Chapter III: Impact of renewable energy generation

1. Introduction

The first counterfactual policy under consideration relates to the impact of renewable energy procurement—taken here to mean wind- and solar-fuelled generation—on the electricity market. For greater clarity, even though water-fuelled generation is renewable in nature it is not included in the definition of renewable energy that is relevant in this analysis.

The issue of negative externalities associated with carbon emissions—including from electricity generators—has been faced by many political jurisdictions throughout the world. The purpose of this chapter is to estimate the cost of Ontario's renewable energy policy in terms of its effect on carbon emissions. With this knowledge, the cost of carbon dioxide (CO₂) abatement in Ontario's electricity market can be compared to CO₂ abatement cost data observed in other markets as a result of alternative strategies. Such a comparison allows for conclusions to be drawn regarding the cost effectiveness of Ontario's entry policy.

While the regulator's generation procurement policy extends, as described in chapter II, beyond renewable energy generation, the counterfactual policy under consideration in this chapter focuses exclusively upon them. Under the counterfactual policy described thus far, the amount of generating capacity based in Ontario would be lower than under the base case. Given the intermittent nature of wind- and solar-fuelled generators, it is clear that a reduction of 1 MW of renewable generation capacity results in a reduction of less than 1 MWh of output in a typical hour. A reasonable and conservative regarding the reduction of output is 0.328 MWh in a typical hour, that is, that the total energy contribution of renewable energy generators averages 32.8% of

capacity.⁴⁸ It is assumed that the absence of renewable energy generation capacity is off-set by additional natural gas-fuelled generation at that rate.

The chapter proceeds as follows. Section 2 discusses the motivation for and importance of considering this issue. The theoretical impact of the counterfactual policy is described in detail in section 3. Using this as a basis of analysis, section 4 reports counterfactual results, which are then described—in their own right and in relation to the base case constructed in chapter II—in section 5. Section 6 concludes.

2. Importance of issue and motivation of analytical approach

This section discusses the importance of studying the impact of renewable energy generation on the market by describing the magnitude of entry and its cost. A standardised measure of the cost of CO₂-emission abatement is then described. The general analytical approach to estimating this value is then described.

2.1. Importance of issue

Chapter II provided background on the development of the electricity market in Ontario. As discussed there, one important development related to the creation of the regulator's programme of generation procurement. Initially, this programme focused on inducing entry of natural gas-fuelled and, to a much lesser extent, renewable energy electricity generators so as to implement the government's goal of withdrawing coal-

⁴⁸ The Independent Electricity System Operator (IESO) makes planning assumptions in its periodic, medium-term (18 months) assessments of the reliability and operability of Ontario's electricity system. The methodology underlying these assessments assumes that monthly average wind capacity contributions range from 13.4% to 32.8%. These data are estimated from (simulated) historic wind output data. The total energy contribution from wind energy is found to average 29%. The maximum of the monthly average wind capacity contributions—32.8%, associated with January, February, and December—is used in the analysis reported in this chapter. See IESO (November 2011a) and IESO (November 2011b) for additional details.

fuelled generators from the market.⁴⁹ Effectively, it was a carbon dioxide-emission abatement policy.

At the end of 2005, action to achieve the initial goal of the programme was underway.⁵⁰ While many of the generators under contract at that time would not enter the market for several years due to planning and building lead-times, the focus of the regulator's programme shifted away from natural gas-fuelled generation towards renewable energy generation. Especially significant was the implementation of standardised contracts for prospective renewable energy generators in place of request for proposal-type auctions. Two such programmes have existed: the Renewable Energy Standard Offer Program (RESOP)⁵¹ and subsequently the Feed-in Tariff Program (FIT).⁵²

The renewable energy generation programme merits special consideration because it has a significant impact on the electricity market. Figure III-1 illustrates Ontario's installed capacity of renewable energy generation. This capacity was 0 MW at the beginning of 2006 but had risen to approximately 1,915 MW by June 2011. In comparison, in the summer of 2011 there was approximately 35,000 MW of installed

⁴⁹ As described in chapter II, the Ontario Power Authority (OPA), referred to herein as the regulator, was created by the *Electricity Restructuring Act, 2004*. One of the OPA's principle activities was to develop a long-term electricity system plan that would result in the phase-out of coal-fuelled generation in Ontario. See section 34 of the *Electricity Restructuring Act, 2004*, which became section 25.30 of the *Electricity Act, 1998*. This legislative undertaking was in accordance with the 2003 general election platform of the Liberal Party of Ontario, the party that formed the provincial government following that election. See Liberal Party of Ontario (2003).

⁵⁰ See the first annual report of the Ontario Power Authority (OPA, March 2006), which summarises the contracts that had been created up to the end of 2005. Lakeview Generating Station, a coal-fuelled generating station, near Toronto, was withdrawn from service on 30 April 2005. See the Market Surveillance Panel report (MSP, June 2005) related to the six-month period ending April 2005 for additional information regarding developments in the electricity market at that time.

⁵¹ The RESOP was established by the direction of a Ministerial Directive (Ministry of Energy, 2006) issued on 21 March 2006 by Ontario's Minister of Energy.

⁵² The FIT programme was established by the direction of a Ministerial Directive (Ministry of Energy and Infrastructure, 2009) issued on 24 September 2009 by Ontario's Minister of Energy and Infrastructure.

electricity generation capacity of all fuel types located in Ontario.⁵³ Thus, over the first five-year period in which the regulator's procurement policy was in place, renewable energy generation rose from 0% to approximately 6% of capacity. Figure III-2 illustrates the total production of electricity from renewable energy generators. This has risen from an hourly average of 0 MWh per hour at the beginning of 2006 to as high as 680 MWh per hour in February 2011, when it constituted approximately 3.7% of Ontario-based supply.

While the proportions of capacity and production related to renewable energy generation are small, their impact on the wholesale market is magnified by the level of the contract prices they receive. Figure III-3 illustrates the production-weighted

Figure III-1: Capacity of renewable energy generators, by fuel type

⁵³ There were 34,960 MW of generating capacity connected to the IESO-controlled grid in August 2011 (Independent Electricity System Operator, November 2011a). In addition, there were several hundred megawatts of generating capacity embedded within the distribution system, including approximately 235 MW of wind-fuelled capacity (Ontario Power Authority, August 2011).

Figure III-2: Output of renewable energy generators, all fuel types

Figure III-3: Average contract price of renewable generation

average of contract prices received by renewable energy generators from March 2006 onward. This series begins at a level of \$135 per MWh, corresponding to the contract price of wind-fuelled renewable energy generation discussed in chapter II, and stays there for many months until solar-fuelled renewable energy generation began to enter the market (as illustrated in Figure III-1). When this began to occur, the average contract price rose above \$135 per MWh, reflecting the \$420 per MWh contract price offered to solar-fuelled generation.

Figure III-4 illustrates the contents of Figures II-3 and III-3 jointly: the wholesale market clearing price, the global adjustment rate, the all-in price, and the average renewable energy contract price. It is immediately evident that renewable energy contract prices are well in excess of the wholesale market clearing price. As described in the construction of the regulator's budget constraint in chapter II, contractually guaranteed

Figure III-4: Average contract price of renewable energy and other prices

revenue that is not obtained from the wholesale market is provided by the regulator in the form of out-of-market top-up payments. Figure III-4 makes clear that these top-up payments, funded through the global adjustment mechanism, constitute a majority of the revenue received by the typical renewable energy generator. It is in this way that the impact of renewable energy production on the market is magnified well beyond the level suggested by the fraction of total capacity and output associated with renewable energy.

Presentation of these data is not intended to act as an analysis of renewable energy in its own right, but rather to illustrate the importance of policy-induced entry on the market and to motivate further analysis.

2.2. Motivation of analytical approach

The most useful measure of the (average) social cost of CO₂-emission abatement as a result of the programme is the number of dollars spent per tonne of CO₂ abated, *i.e.*, \$/tonne of CO₂. This is because it is a normalisation that facilitates comparison to alternative approaches taken in other jurisdictions and markets. This calculation requires two inputs: the total (social) cost of the programme in dollars and the number of tonnes of CO₂ emissions abated as a result of the expenditure.

The model developed and reported in chapter II can be used to find each of these inputs. Calculation of each value is described in turn.

The cost of the programme in social terms can be estimated by calculating the amount by which total surplus differs under the counterfactual policy of no renewable energy generation in comparison to the base case. Surplus is obtained by each of the four types of economic agents considered: consumers based in Ontario (Ontario-based demand), producers based in Ontario (Ontario-based supply), and inter-jurisdictional traders

(imports and exports). The impact of the counterfactual on each of these groups of agents must be considered.

Ontario-based consumers pay the all-in price, which is the sum of the wholesale market clearing price and the GA rate. The impact of the counterfactual policy need not have symmetric effects on the components of this price. That is, one component could increase while the other decreases. Since Ontario-based consumers pay both, it is the net impact of the counterfactual policy that is relevant to consumers. Any change of the all-in price, therefore, impacts consumers' surplus. The effects of the individual components of the all-in price are not considered.

Traders who export electricity buy it in the wholesale market and pay the wholesale market clearing price.⁵⁴ These consumers do not pay the GA rate on their purchases. As a result, a change of the wholesale market clearing price impacts the surplus they obtain from their activities while they are indifferent to the (direct) effect a changing GA rate.

Similarly, traders who import electricity sell it in the wholesale market and receive the wholesale market clearing price.⁵⁵ As a result, a change of the wholesale market clearing price impacts the surplus they obtain from their activities.

The last group of relevant economic agents (aside from the government) is Ontario-based producers. As described in detail in chapter II and Appendices II-B and II-C, the incentives faced by these producers are not uniform across all firms. Some producers are significantly exposed to changes of the state of the wholesale market, the wholesale

⁵⁴ The impact of transmission system congestion on electricity pricing is ignored in this chapter. This issue is revisited in significant detail in chapter V in relation to an assessment of Ontario's market for financial transmission rights (FTR).

⁵⁵ See the previous footnote regarding the impact of transmission system congestion on the electricity market.

market clearing price in particular. The hydroelectric generators owned by Ontario Power Generation (OPG) are an example of a class of producers of this type. A change of the wholesale market clearing price affects the surplus obtained by such producers.

Other producers are indifferent to the state of the wholesale market. Generators that operate under fixed-price contracts, such as non-utility generators (NUGs), are an example of a class of producers of this type. These firms receive the same, contractually-specified price per unit of output irrespective of the wholesale market clearing price through the payment of out-of-market top-ups by the regulator. While the wholesale market clearing price may change under the counterfactual policy, exactly off-setting changes in the out-of-market top-up payments nullify the impact on such firms. Thus, the surplus obtained by such firms does not change as a result of the counterfactual policy.

The exception among generators that operate under fixed-price contracts are those that would not have entered in the first instance under the counterfactual policy. Any surplus that would have been obtained by these firms associated with entering the market is lost under the counterfactual policy. Renewable energy generators—such as wind- and solar-fuelled generators—fall in this category in relation to the particular counterfactual policy under consideration. If, however, the contract prices offered by the regulator's programme to induce entry by renewable energy generators are set so as to do so at lowest cost, then the entering firms will earn approximately zero producers' surplus. In this case, there would be no loss of surplus associated with such firms not entering the market under the counterfactual policy.

The change of total surplus associated with the counterfactual policy of an absence of the regulator's programme of policy-induced entry of renewable energy generation is the sum of the individual effects outlined above. This can be thought of as the social

cost of the obtaining the environmental effects of the programme for all relevant market participants collectively.⁵⁶

The final component of the wholesale market equilibrium is the budget constraint of the regulator itself, equation (II-8). Before considering this particular budget constraint, consider the impact on total surplus of a revenue-seeking government levying taxes on sales in general. In the classic analysis of the welfare effects of a distortionary tax, the imposition of a tax on a commodity results in a wedge emerging between the price paid by consumers and the price received by producers. The size of the wedge is the tax rate. In a typical case, there is a transfer of surplus from both consumers and producers to the government. This revenue is not considered to constitute a total loss of social welfare because it can be used to finance either lump-sum transfers to consumers or some other socially valuable endeavour. See Mas-Colell, Whinston, and Green (1995, p. 331) for further discussion. In the context of Ontario's electricity market, the revenue raised by the regulator is used to fund programmes whose effects are felt within the market itself. Of particular importance is the use of these revenues to shift the supply curve by, for instance, running programme of policy-induced entrance of renewable energy generators. In any event, most of the revenue collected by the regulator is not used to finance either lump-sum transfers to consumers or some other socially valuable endeavour.⁵⁷ This is not to say that the regulator's revenue itself constitutes a loss of surplus. Since the regulator spends each dollar it raises within the electricity market, this revenue again appears in the surplus calculations of the economic agents discussed above.

⁵⁶ Total surplus is presumably greater under the counterfactual policy than under the base case. This presumption is based in the expectation that policy-induced entry into a market is not free.

⁵⁷ Some of the regulator's expenditures do not directly impact the position of the supply curve. For instance, conservation spending. These expenditures are not considered to constitute a loss of surplus. Irrespective of this assumption, since such expenditures are constant across all counterfactual policies considered in this chapter (and the next), there can be no change in surplus associated with them that must be considered when comparing a counterfactual policy to the base case.

In the context of Ontario's electricity market, since both the GA rate and the level of Ontario-based demand may change under the counterfactual policy equilibrium, the amount of revenue collected by the regulator may also change. Given that the regulator's budget must balance, the amount of funds distributed by the regulator must change symmetrically. Thus, the change in the regulator's revenue will feed through the regulator and manifest itself in the outcomes of the economic agents discussed above.

To recapitulate, consider the counterfactual policy from the opposite perspective, that is, by thinking about the base case as having no renewable energy generators and the counterfactual policy as their contracted entry. Assume again that the entering firms earn zero economic profit, that is, the revenue they receive is exactly equal to the cost—including fixed cost—they incur. The cost of covering the fixed cost associated with entry is entirely a dead-weight loss from the perspective of the market. The loss, which manifests itself in the market through the GA rate, is incurred against consumers through a higher all-in price and non-contracted producers through a lower wholesale market clearing price. Not considering the avoidable nature of fixed cost under the counterfactual policy amounts to assuming that renewable energy capacity is free.

The number of tonnes of CO₂ emissions abated by the programme can be determined by consideration of the difference in the composition of Ontario-based supply between the base case and the counterfactual policy. In particular, under the counterfactual policy there is no output from renewable energy generators. The difference in total output must, therefore, come from producers that emit CO₂ as they produce electricity. This incremental output is assumed to come from natural gas-fuelled generators.⁵⁸

⁵⁸ It is assumed that baseload generators—hydro and nuclear in particular—as well as peaking hydro generators are fully utilised under both the base case and the counterfactual policy. Since coal-fuelled

With these results, the average cost of abating one tonne of CO₂ emissions under the programme of policy-induced entrance of renewable energy generators can then be estimated. The details of the necessary calculations are reported in the next section.

3. Analytical approach and anticipated effects

As described in the previous section, there are two aspects to the calculation of the cost of CO₂ emission abatement under the regulator's programme of generation procurement. First, there is the change in total surplus as a result of the programme. Second, there is the change in CO₂ emissions as a result of the programme. The previous section also outlined how these calculations would be made in general terms. A detailed description is provided here.

Section 3.1 describes how the counterfactual equilibrium is modelled in the context of the model introduced in chapter II. Sections 3.2 and 3.3 describe, respectively, how the change in total surplus and the change in CO₂ emissions between the counterfactual policy and the base case are measured. The cost of CO₂ emission abatement described in section 3.4.

3.1. Counterfactual equilibrium

In order to make these calculations, the details of the appropriate counterfactual policy must be specified. The presence of renewable energy generation impacts the market equilibrium through three mechanisms: it impacts Ontario-based supply, it contributes costs (potentially negative) that must be recovered by the GA, and it displaces other types of generation capacity.

generators are being phased-out of the market, the incremental supply must come from the only other source: natural gas-fuelled generators.

To determine the impact of the counterfactual policy, the three mechanisms described above must be accounted for. First, the amount of baseload supply must be amended to exclude the contributions made to it by renewable energy. Second, the equation that describes the regulator's expenses must be amended to exclude out-of-market top-up payments to renewable energy generators. Third, that must be further amended to include costs associated with payments to the non-renewable energy generation capacity that replaces renewable generation.

In terms of the market model introduced in chapter II, the first mechanism impacts the baseload time series in

$$q_t^s = \gamma_0 + \gamma_1 p_t + \gamma_2 fuel_t + \gamma_3 baseload_t + \varepsilon_{1t} \quad (II-1)$$

which would be lower by the magnitude of observed energy output from wind- and solar-fuelled generators located in Ontario. Crucially, the econometrically-derived coefficient estimates are assumed to be unchanged. In other words, the Ontario-based supply curve shifts to the left under the counterfactual.

The second and third mechanisms impact aspects of the regulator's expenses and, therefore, appear in the regulator's budget constraint. In particular, out-of-market top-up payments required to induce renewable energy entry in the first instance are components of the regulator's expenses and, therefore, appear in the regulator's budget constraint. A no-renewable energy counterfactual policy would be associated with the absence of these payments (costs). In particular,

$$\begin{aligned} Exp_t = & q_t^{wind} * (135 - P_t) + q_t^{solar} * 0.19 * (420 - P_t) \\ & + 1577 * (75 - P_t) + q_t^{nuclear} * (55 - P_t) + 1900 * (33 - P_t) \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (II-7)$$

would reflect both the absence of wind- and solar-fuelled output, *i.e.*, $q_t^{wind} = q_t^{solar} = 0$, and a scaling-up of natural gas capacity costs in proportion to the amount of renewable energy generation capacity eliminated as described in section 2.

Holding the GA rate constant, a reduction of supply associated with the absence of output from renewable energy generators would result in an increase of the wholesale market clearing price, along with increased imports, and decreased Ontario-based demand and exports. Due to the higher wholesale market clearing price, the generators that remain in the market would earn greater revenue than otherwise. A subset of these generators operates under contractual arrangements with the regulator that entitles them to receive the out-of-market top-up payments described in chapter II and Appendix II-B. These payments are, in aggregate, reduced as a result of the higher wholesale market clearing price. The result is that the regulator's budget has a surplus, thereby placing downward pressure on the GA rate initially held constant.

Likewise, a reduction of supply associated with the absence of output from renewable energy generators would eliminate the out-of-market top-up payments that were necessary to induce entry of such generation in the first instance.⁵⁹ As a result, the expenses included in equation (II-7) would be less than otherwise, thereby placing additional downward pressure on the GA rate.

Taken together, a reduction of supply associated with the absence of output from renewable energy generators would raise the wholesale market clearing price and reduce the GA rate. The net impact on the all-in price depends principally on the average contract price paid for renewable energy relative to the wholesale market clearing price. Since renewable energy generation is procured at average contract prices

⁵⁹ The average prices to which renewable energy generation is topped-up are well above average market clearing prices. This is illustrated in Figure III-4. It is because of this relationship that such generation will only enter the market under special contractual terms.

several times the average wholesale market clearing price, the net impact on the all-in price is expected to be negative.⁶⁰

Offsetting this effect is the additional cost borne by the regulator of the natural gas-fuelled capacity that replaces the renewable energy capacity. As described in section 2, the amount of incremental natural gas-fuelled capacity is defined to be a constant proportion—32.8%—of the renewably-fuelled capacity eliminated under the counterfactual policy. Relative to the former effects, the latter effect is expected to be small.⁶¹

A lower all-in price implies that Ontario-based demand will be higher. A higher wholesale market clearing price implies that exports will be lower and imports will be higher.

The impact of the regulator's policy of generation procurement as it relates to renewable energy can be looked at from the opposite perspective compared to that above, that is, the impact on the wholesale market equilibrium of the entry of renewable energy generation. Holding the GA rate constant, such entry increases supply at all price levels, thereby lowering the wholesale market clearing price. The lower wholesale market clearing price means those contractual payments to non-renewable generators will increase, creating a budget deficit for the regulator, thereby placing upward pressure on the GA rate. Given the relatively high costs associated with inducing the entry of renewable generation into the market, the resulting equilibrium is expected to

⁶⁰ See previous footnote. In Appendix II-C it is shown that if the (capacity) weighted-average of contract prices offered by the regulator exceeds the wholesale market clearing price that would prevail in the absence of regulatory intervention regarding supply, then the GA rate must be positive. Given that contract prices offered to renewable energy generators exceed the levels offered to other types of generation, entry of renewable energy generation capacity raises this weighted-average and, by extension, the GA rate. Thus, under the counterfactual policy both are lower than otherwise.

⁶¹ To begin with, natural gas-fuelled capacity is less expensive than renewable energy capacity. This relationship is reflected by the relatively high contract prices offered to renewable energy generators.

be one where the wholesale market price is lower, but the GA rate and all-in price are both higher.

3.2. Change of total surplus

Once the counterfactual policy equilibrium has been simulated, the associated change in total surplus can be calculated. To facilitate this discussion, use is made of modified versions of Figures II-6, II-7, II-9, and II-10, the Figures that illustrate base case Ontario-based supply, imports, Ontario-based demand, and exports.

A particular notation convention is adopted. Base case values are denoted with superscript asterisks (*). Counterfactual policy values are denoted with superscript primes ('). Additional notational conventions are defined locally where necessary.

First, consider the impact of the counterfactual policy on the surplus obtained by Ontario-based supply. As described above, the impact of changing wholesale market conditions on producers varies according to the contractual arrangements that exist between individual producers and the regulator. Some producers are exposed to the wholesale market clearing price and others are not. Those that are not exposed lack exposure because they receive compensation from the regulator that neutralises the impact on them of changing wholesale market conditions. As a result, such producers do not experience a change of surplus under the counterfactual policy relative to the base case. The exception is those renewable energy generators that are eliminated from the market under the counterfactual policy. If, however, these generators were induced to enter the market with contracts that ensured approximately zero economic profits, then these generators would not lose surplus under the counterfactual policy either. Those non-contracted generators that are exposed to the wholesale market clearing price gain surplus if the price rises and lose surplus if the price falls. The details of

these contractual arrangements are described in greater detail in section 2, as well as in chapter II.

Conceptually, a supply curve that corresponds to the subset of non-contracted Ontario-based generators that are exposed to the wholesale market clearing price can be constructed. Since such a curve represents a fraction of Ontario-based supply, it must relate a smaller quantity to each price than either the base case or counterfactual Ontario-based supply. For notational convenience, this sub-supply curve is denoted with superscript noughts (^o).

Figure III-5 illustrates base case and counterfactual policy Ontario-based supply. The sub-supply curve related to non-contracted generation is also illustrated. The base case equilibrium wholesale market clearing price is p_t^* , while the counterfactual policy equilibrium wholesale market clearing price is p_t' . As argued above, and with foreknowledge of the results to be reported in the next section, the figure assumes that $p_t^* < p_t'$.

As stated above, this price change only impacts the surplus obtained by non-contracted generators. The amount of supply provided by non-contracted supply can be read off the sub-supply curve. In particular, base case non-contracted supply is $S^o(p_t^*)$ while counterfactual non-contracted supply is $S^o(p_t')$. The result that $S^o(p_t^*) < S^o(p_t')$ follows from $p_t^* < p_t'$ and the presumption that non-contracted supply is increasing in the wholesale market clearing price. The change in surplus obtained by Ontario-based supply is the shaded area in Figure III-5 and can be represented mathematically as

$$\begin{aligned}\Delta PS_t^{Ontario\ Supply} &= \int_{p_t^*}^{p_t'} S^o(x) dx \\ &= \frac{1}{2} [S^o(p_t') + S^o(p_t^*)] * [p_t' - p_t^*]\end{aligned}\tag{III-1}$$

Figure III-5: Changing surplus of Ontario-based supply

The second equality in equation (III-1) follows from the linear specification of the various supply curves resulting in the shaded area in Figure III-5 being a trapezoid.

An increase of the wholesale market clearing price under the counterfactual policy will increase the surplus obtained by non-contracted Ontario-based generators (and by extension Ontario-based generators collectively). That is $\Delta PS_t^{Ontario\ Supply} > 0$. This change of surplus obtained by Ontario-based supply constitutes the first part of the change of total surplus under the counterfactual policy.

Figure III-6: Changing surplus of import supply

The impact of the counterfactual policy on the surplus obtained by other economic agents in the market is more straightforward to measure because the counterfactual policy does not impact the fundamental characteristics of these agents, just the price they pay for their consumption or are paid for their supply.

Figure III-6 illustrates the change of surplus obtained by importers of electricity to Ontario under the counterfactual policy. Surplus changes because the price paid to imports, the wholesale market clearing price, changes. The change in surplus is the shaded area in Figure III-6 and can be represented mathematically as

$$\begin{aligned}\Delta PS_t^{Imports} &= \int_{p_t^*}^{p_t'} \hat{q}_t^i(x) dx \\ &= \frac{1}{2} [q_t^{i'} + q_t^{i*}] * [p_t' - p_t^*]\end{aligned}\tag{III-2}$$

where $\hat{q}_t^i(x)$ denotes the level of exports at price x . This area is also a trapezoid due to

the linear specification of the import supply curve. An increase of the wholesale market clearing price under the counterfactual policy will increase the surplus obtained by importers. That is $\Delta PS_t^{Imports} > 0$. This change of surplus obtained by importers constitutes the second part of the change of total surplus under the counterfactual policy.

Figure III-7 illustrates the change of surplus obtained by Ontario-based consumers of electricity under the counterfactual policy. Surplus changes because the price paid by consumers, the all-in price (the sum of the wholesale market clearing price and the GA rate), changes. The change in surplus is the shaded area in Figure III-7 and can be represented mathematically as

$$\begin{aligned}\Delta CS_t^{Ontario\ Demand} &= \int_{p_t' + g_t'}^{p_t^* + g_t^*} \hat{q}_t^d(x) dx \\ &= \frac{1}{2} [q_t^{d'} + q_t^{d*}] * [(p_t^* + g_t^*) - (p_t' + g_t')] \end{aligned} \quad (III-3)$$

where $\hat{q}_t^d(x)$ denotes the level of Ontario-based consumption at price x . This area is also a trapezoid due to the linear specification of the Ontario-based demand curve. A decrease of the all-in price under the counterfactual policy will increase the surplus obtained by Ontario-based consumers. That is $\Delta CS_t^{Ontario\ Demand} > 0$. This change of surplus obtained by Ontario-based consumers constitutes the third part of the change of total surplus under the counterfactual policy.

Figure III-8 illustrates the change of surplus obtained by exporters of electricity from Ontario under the counterfactual policy. Surplus changes because the price paid for exports, the wholesale market clearing price, changes. The change in surplus is the shaded area in Figure III-8 and can be represented mathematically as

Figure III-7: Changing surplus of Ontario-based demand

$$\begin{aligned}
 \Delta CS_t^{Exports} &= - \int_{p_t^*}^{p_t'} \hat{q}_t^e(x) dx \\
 &= - \frac{1}{2} [q_t^{e'} + q_t^{e*}] * [p_t' - p_t^*]
 \end{aligned} \tag{III-4}$$

where $\hat{q}_t^e(x)$ denotes the level of exports at price x . This area is also a trapezoid due to the linear specification of the export demand curve. An increase of the wholesale market clearing price under the counterfactual policy will decrease the surplus obtained

Figure III-8: Changing surplus of export demand

by exporters. This is the source of the negative sign in equation (III-4). That is $\Delta CS_t^{Exports} < 0$. This change of surplus obtained by exporters constitutes the fourth part of the change of total surplus under the counterfactual policy.

The change of total surplus under the counterfactual policy is simply the sum of the changes in surplus obtained by each of the four groups of economic agents considered. That is

$$\Delta TS_t = \Delta PS_t^{Ontario Supply} + \Delta PS_t^{Imports} + \Delta CS_t^{Ontario Demand} + \Delta CS_t^{Exports} \quad (III-5)$$

Since the four terms of equation (III-5) are not expected to be of the same sign, the sign of ΔTS_t itself is ambiguous. The change in total surplus is measured in dollars.

The expected results illustrated above depend on the wholesale market clearing price being higher and the all-in price being lower under the counterfactual policy than under the base case, that is: $p_t' > p_t^*$ and $p_t' + g_t' < p_t^* + g_t^*$. If this were to turn out not to be the

case, equations (III-1), (III-2), (III-3), and (III-4) would continue to represent changes of surplus obtained by the various groups of economic agents, but the signs of the changes would differ. Equation (III-5) would continue to represent the change of total surplus due to the counterfactual policy.

3.3. Change of CO₂ emissions

Generators that are fuelled by fossil fuels emit CO₂ as they produce electricity. Other generators, including those wind- and solar-fuelled, do not. Once the counterfactual policy equilibrium has been simulated, the associated change in CO₂ emissions can be calculated. This calculation depends on how the composition of supply differs under the counterfactual policy from the base case. Attention here is restricted to CO₂ emissions from Ontario-based supply alone.

The amount of Ontario-based supply under the base case and the counterfactual policy is q_t^{S*} and $q_t^{S'}$, respectively. The difference between the two values is the change of Ontario-based supply under the counterfactual policy, that is

$$\Delta q_t^S = q_t^{S'} - q_t^{S*} \quad (\text{III-6})$$

This can be seen in Figure III-5.

Assume that the marginal Ontario-based supplier is a natural gas-fuelled generator. Then the change in Ontario-based supply that is produced from CO₂-emitting generators can be decomposed into two parts: the change in the level of supply and the change in the composition of supply. That is

$$\Delta q_t^{S, \text{Carbon Emitting Supply}} = \Delta q_t^S + (q_t^{\text{wind}} + q_t^{\text{solar}}) \quad (\text{III-7})$$

Consider each of these effects. First, a change in the level of supply would result in a change in output of the marginal, CO₂-emitting supplier. Second, the renewable energy

generation that is eliminated from the market under the counterfactual policy would be replaced by the marginal, CO₂-emitting supplier. The change is reported in average MWh per hour of electricity.

Define θ to be the CO₂ emissions in tonnes per MWh of electricity generated by the marginal supplier, which is assumed to be natural gas-fuelled. Effectively, θ measures the CO₂ intensity of the marginal supplier and is reported in tonnes per MWh of electricity generation. Then the change of CO₂ emissions associated with the counterfactual policy is

$$\Delta CO2_t = \theta * \Delta q_t^{s, Carbon\ Emitting\ Supply} \quad (III-8)$$

In other words, the change in carbon dioxide emissions under the counterfactual policy is the change in the amount of electricity generated by natural gas-fuelled producers multiplied by the CO₂-intensity of those generators. The change is measured in tonnes of CO₂.⁶²

Detailed analysis of the technical characteristics of typical natural gas-fuelled generators allows for θ to be estimated. Gagnon, Bélanger, and Uchiyama (2002) report that a reasonable value of θ in a North American (or European) context is 0.443 tonnes of CO₂ per MWh of electricity.⁶³

⁶² This is because θ is measured in tonnes of CO₂ per MWh of electricity generation and $\Delta q_t^{s, Carbon\ Emitting\ Supply}$ is measured in MWh of electricity generated.

⁶³ Equation (III-8) captures the change in CO₂ emissions associated with increased use of natural gas-fuelled generators under the counterfactual policy. This analysis ignores the stand-by generation, typically natural gas-fuelled, that is necessary under the base case to act as back-up for renewable energy generation due to its intermittent nature. Also ignored is the fact that renewable energy generation itself is not truly free of CO₂ emissions. For instance, Pehnt (2006) reports that the θ associated with renewable energy generation equals approximately 0.010 for wind- and solar-fuelled generators.

3.4. Cost of CO₂ emission abatement

The results obtained from the analyses reported in sections 3.2 and 3.3 can be used to estimate the average cost of carbon dioxide emission abatement (COA).

In particular, the COA is the ratio of equations (III-5) and (III-8). That is

$$COA_t = \Delta TS_t / \Delta CO2_t \quad (III-9)$$

Since the change in total surplus is measured in dollars and the change in CO₂ emissions is measured in tonnes of CO₂, then COA is measured in dollars per unit of CO₂ abated (as a result of the regulator's programme of renewable energy generation capacity procurement). This is a standardised measure of the cost of CO₂ abatement that can be used to compare Ontario's approach with those taken in other markets and jurisdictions.

4. Empirical results

This section reports the empirical results associated with implementation of the analytical approach described in the previous section. Section 4.1 reports the counterfactual policy equilibrium under which no renewable energy generation capacity is induced by the regulator to enter the market. The results are contrasted with the base case in the related discussion. Section 4.2 reports the change in total surplus between the counterfactual policy and the base case, while section 4.3 reports the associated change in CO₂ emissions. Section 4.4 reports the estimated cost of CO₂ abatement due to Ontario's programme of renewable energy capacity procurement.

4.1. Counterfactual equilibrium

Table III-1 reports the mean and standard deviation of each of the endogenous variables

in the model under both the base case and the counterfactual policy. The statistics are presented for all 110 months of the study period and the last 24 months only.

Figures III-9, III-10, and III-11 illustrate the base case and no-renewable energy counterfactual policy values for the wholesale market clearing price, the GA rate, and the all-in price, respectively.

Qualitatively, the counterfactual policy results reported in Table III-1 correspond with the theoretical expectations outlined in section 3 for both (i) all 110 months of the study period and (ii) the last 24 months of the study period.

These results, in addition to Figures III-9, III-10, and III-11, show that the impact on market equilibrium of the regulator's policy of generation procurement as it relates to

*Table III-1: Base case and no-renewable energy counterfactual policy statistics
All months and last 24 months*

Variable	Case	All Months		Last 24 Months	
		Mean	Std. Dev.	Mean	Std. Dev.
q_t^s	Base Case	17,570.2	1,129.6	17,583.2	1,182.9
	No Renew.	17,568.3	1,120.0	17,597.5	1,153.0
q_t^i	Base Case	949.0	306.3	655.8	195.9
	No Renew.	975.9	288.9	736.9	187.7
q_t^d	Base Case	16,685.5	1,168.4	16,263.8	1,303.0
	No Renew.	16,738.8	1,142.1	16,443.7	1,265.0
q_t^e	Base Case	1,370.7	459.6	1,519.2	217.1
	No Renew.	1,341.9	450.1	1,432.4	219.4
p_t	Base Case	49.83	11.91	37.46	11.05
	No Renew.	51.16	10.74	41.46	10.41
g_t	Base Case	7.71	12.77	24.85	11.38
	No Renew.	5.75	10.48	18.72	9.75
$p_t + g_t$	Base Case	57.54	5.09	62.31	1.87
	No Renew.	56.91	4.69	60.19	1.27

Figure III-9: Base case and no-renewable energy counterfactual policy wholesale market clearing price

renewable energy has been growing through time. This finding is consistent with the expectations regarding how the regulator's policy would manifest itself, namely that the impact would gradually appear in the market as the generation procured entered service.

The results indicate that consumers located in Ontario faced higher all-in electricity prices as a result of the procurement policy. The results also indicate that non-contracted generators lost quasi-rents as a result of the procurement policy. This is a result of the policy's negative effect on the wholesale market clearing price.

In particular, over the whole study period, the analysis concludes that in the absence of renewable energy generation the average wholesale market clearing price would be \$51.16 per MWh instead of \$49.83, an increase of \$1.33 per MWh (2.7%). The GA rate

Figure III-10: Base case and no-renewable energy counterfactual policy global adjustment

would be \$5.75 per MWh instead of \$7.71 per MWh, a reduction of \$1.96 per MWh (25.4%). The Ontario all-in price would be \$56.91 per MWh instead to \$57.54 per MWh, a reduction of \$0.63 per MWh (1.1%). With respect to quantities, Ontario-based demand would increase by 53.3 MWh per hour (0.3%), imports would increase by 26.9 MWh per hour (2.8%), exports would decrease by 28.8 MWh per hour (2.1%), and Ontario-based supply, net of the reduction due to the absence of renewable generation, would decrease by 1.9 MWh per hour (0.0%).

From the opposite perspective, implementation of the renewable energy procurement policy resulted in the all-in price paid by Ontario-based demand increasing by \$0.63 per MWh (1.1%) and the wholesale market clearing price received by non-contracted Ontario-based generation decreasing by \$1.33 per MWh (2.6%). Thus, the total cost on a

Figure III-11: Base case and no-renewable energy counterfactual policy all-in price

per MWh basis borne jointly by Ontario-based demand and non-contracted Ontario-based supply is \$1.96 per MWh. This is definitionally equal to the reported increase of the GA rate. Ontario-based demand declined by 53.3 MWh per hour (0.3%), imports declined by 26.9 MWh per hour (2.8%), exports increased by 28.8 MWh per hour (2.1%), and Ontario-based supply increased by 1.9 MWh per hour (0.0%).

Over the last 24 months of the study period, the simulations report that in the absence of renewable energy generation the wholesale market clearing price would be \$41.46 per MWh instead of \$37.46 per MWh, an increase of \$4.00 per MWh (10.7%). The GA rate would be \$18.72 per MWh instead of \$24.85 per MWh, a reduction of \$6.13 per MWh (24.7%). The Ontario all-in price would be \$60.19 per MWh instead of \$62.31 per MWh, a reduction of \$2.12 per MWh (3.4%). With respect to quantities, Ontario-based demand would increase by 179.9 MWh per hour (1.1%), imports would increase by 81.1

MWh per hour (12.4%), exports would decrease by 86.8 MWh per hour (5.7%), and Ontario-based supply, net of the reduction due to the absence of renewable generation, would *increase* by 14.3 MWh per hour (0.1%).

From the opposite perspective, implementation of the renewable energy procurement policy resulted in the all-in price paid by Ontario-based demand to increase by \$2.12 per MWh (3.5%) and the wholesale market clearing price received by non-contracted Ontario-based generation decreasing by \$4.00 per MWh (9.6%). Thus, the total cost on a per MWh basis borne jointly by Ontario-based demand and non-contracted Ontario-based supply is \$6.13 per MWh. This is definitionally equal to the reported increase of the GA rate.⁶⁴

Policy-induced entrants were not affected by the procurement policy by virtue of the contractual terms under which they entered the market. Non-contracted generators and Ontario-based consumers experienced losses as a result of, respectively, a reduction of the wholesale market clearing price and an increase of the all-in price. The results also indicate that the procurement policy incentivised incrementally greater exports. Since the average price paid for exports declined, infra-marginal exports became more profitable than they would have otherwise been. For analogous reasons, imports faced the opposite outcome. More precise measures of the impact of the procurement policy are reported in the next section where the surplus—and change thereto—obtained by each group of economic agents is considered.

Finally, while the data used in this study are observed at a monthly frequency, it is useful to recall that the wholesale market clearing price varies at a 5-minute frequency

⁶⁴ It is due to rounding that \$2.12 and \$4.00 do not sum to \$6.13.

whereas the GA rate varies at a 1-month frequency.⁶⁵ Thus, the growing importance of the GA rate in the all-in price of electricity can be interpreted as a shift away from incremental cost pricing towards average cost pricing, an outcome which has negative implications for the allocative efficiency of the wholesale market.

4.2. Change of total surplus

The change in total surplus is the sum of the changes in surplus obtained by each of the four groups of economic agents. Formulae for the change of surplus obtained by Ontario-based supply, imports, Ontario-based demand, and exports under the counterfactual policy compared to the base case are given by equations (III-1), (III-2), (III-3), and (III-4), respectively.

Table III-2 reports the mean and standard deviation of the changes in surplus obtained in an average hour by each of the four groups of economic agents under the counterfactual policy.⁶⁶ The change of total surplus is reported as well. The statistics are presented for all 110 months of the study period and the last 24 months only. Figure III-12 illustrates the changes in surplus obtained in an average hour by each of the four groups of economic agents across the months of the study period. The related change in total surplus is illustrated in Figure III-13.

The average hourly data presented above can be transformed into monthly total data by multiplying by the number of hours in the appropriate month. The mean and standard deviation of these transformed data are reported in Table III-3. Figure III-14 illustrates the changes in monthly surplus obtained by each of the four groups of economic agents. The change in monthly total surplus is illustrated in Figure III-15.

⁶⁵ An hourly wholesale market clearing price, known as the hourly Ontario energy price (HOEP), is the mean of the twelve 5-minute prices observed within each hour.

⁶⁶ The data are reported on an hourly basis in the sense that they indicate changes in surplus for each hour in a month. Monthly total data must account for the total number of hours in each month.

*Table III-2: Changes of surplus under the counterfactual policy
By economic agent on an hourly basis, in dollars
All months and last 24 months*

Economic Agent	All Months		Last 24 Months	
	Mean	Std. Dev.	Mean	Std. Dev.
Ontario-based supply	5,499	7,670	16,269	8,129
Imports	1,025	1,275	2,712	1,234
Ontario-based demand	10,169	16,788	34,229	20,513
Export	-1,999	2,722	-5,883	2,772
All agents combined	14,695	22,770	47,327	26,540

*Table III-3: Changes of surplus under the counterfactual policy
By economic agent on a monthly basis, in millions of dollars
All months and last 24 months*

Economic Agent	All Months		Last 24 Months	
	Mean	Std. Dev.	Mean	Std. Dev.
Ontario-based supply	4.004	5.559	11.840	5.818
Imports	0.747	0.922	1.972	0.867
Ontario-based demand	7.410	12.209	24.934	14.875
Export	-1.456	1.977	-4.284	1.992
All agents combined	10.704	16.538	34.462	19.166

The data reveal that the impact of the regulator's policy of renewable energy procurement on both total surplus and its components has been growing through time. This finding corresponds to the findings noted in the previous section regarding the impact of the policy on the wholesale market clearing price, the GA rate, the all-in price, and the various endogenously-determined quantities. It is consistent with the expectations regarding how the regulator's policy would manifest itself, namely that the impact would gradually appear in the market as the generation procured entered service.

Figure III-12: Changes of surplus, by groups of economic agents, hourly basis

Figure III-13: Change of total surplus, hourly basis

Figure III-14: Changes of surplus, by groups of economic agents, monthly basis

Figure III-15: Change of total surplus, monthly basis

The results indicate that consumers located in Ontario faced a loss of surplus as a result of the procurement policy. The channel through which this loss was incurred was that the all-in price increased as a result of the policy. The results also recognise losses of surplus incurred by non-contracted generators and importers as a result of a reduced wholesale market clearing price. Correspondingly, exporters gain surplus. In the context of the data presented, the losses discussed can be identified as the gains associated with the counterfactual policy relative to the base case while the gains discussed can be identified as the losses associated with the counterfactual policy relative to the base case.

In particular, over the whole study period, the analysis concludes that total surplus would have averaged \$14,695 higher per hour under the counterfactual policy than the base case. Of this total, hourly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged \$10,169, \$5,499, and \$1,025 higher, respectively, while hourly surplus attributable to exporters would have averaged \$1,999 lower. On an aggregate monthly basis, total surplus would have averaged \$10.7 million higher under the counterfactual policy than the base case. Of this total, monthly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged \$7.4 million, \$4.0 million, and \$0.7 million higher, respectively, while monthly surplus attributable to exporters would have averaged \$1.5 million lower.

Reflecting the implementation of the procurement programme through time, all of these averages are higher over the last 24 months of the study period than over the whole study period. In particular, over the whole study period, the analysis concludes that total surplus would have averaged \$47,327 higher per hour under the counterfactual policy than the base case. Of this total, hourly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged \$34,229,

\$16,269, and \$2,712 higher, respectively, while hourly surplus attributable to exporters would have averaged \$5,883 lower. On an aggregate monthly basis, total surplus would have averaged \$34.5 million higher under the counterfactual policy than the base case. Of this total, monthly surplus attributable to Ontario-based consumers, non-contracted generators, and importers would have averaged \$24.9 million, \$11.8 million, and \$2.0 million higher, respectively, while monthly surplus attributable to exporters would have averaged \$4.3 million lower.

In aggregate, the results show that the procurement policy resulted in a reduction of total surplus of approximately \$1,177.5 million from its commencement in 2006 through to June 2011. Of this total, the loss of surplus from Ontario-based consumers, non-contracted generators, and importers is reported to have been approximately \$815.1 million, \$440.4 million, and \$82.2 million, respectively, while the gain in surplus by exporters is reported to have been \$160.2 million.

The (net) loss of total surplus constitutes the social cost of obtaining the CO₂ emission reductions achieved as a result of the regulator's renewable energy procurement policy. The amount of CO₂ emission reductions achieved is the subject of the next section.

4.3. Change of CO₂ emissions

The change of CO₂ emissions resulting from the regulator's programme of renewable energy procurement is due to the change in composition of Ontario-based supply it causes. The reduction of electricity output that is generated through the combustion of fossil fuels is given by equation (III-7). The reduction of CO₂ emissions associated with this change of supply composition is given by equation (III-8).

Table III-4 reports the mean and standard deviation of the changes in CO₂ emissions under the counterfactual policy. The results are reported on an hourly — tonnes per

hour — and a monthly — thousands of tonnes per month — basis. The statistics are presented for all 110 months of the study period and the last 24 months only. Figures III-16 and III-17 illustrate the changes in average hourly and monthly emissions, respectively, across the months of the study period.

The results indicate that the impact of the regulator’s policy of renewable energy procurement on CO₂ emissions has been growing through time, a finding consistent with the expectations regarding how the regulator’s policy would manifest itself, namely that the impact would gradually appear in the market as the generation procured entered service.

In particular, over the whole study period, the analysis concludes that CO₂ emissions would have been an average of 63 tonnes per hour, equivalent to approximately 46 thousand tonnes per month, greater under the counterfactual policy than under the base case. Reflecting the implementation of the procurement programme over time, the analysis reveals that CO₂ emissions would have averaged 191 tonnes per hour, equivalent to approximately 139 thousand tonnes per month, more under the counterfactual policy than under the base case over the last 24 months of the study period.

*Table III-4: Change of CO₂ emissions, amount as noted, hourly and monthly basis
All months and last 24 months*

Basis	All Months		Last 24 Months	
	Mean	Std. Dev.	Mean	Std. Dev.
Hourly (tonnes)	63.35	87.16	191.08	87.02
Monthly (thousands of tonnes)	46.14	63.17	139.10	62.11

Figure III-16: Change of CO₂ emissions, hourly basis

Figure III-17: Change of CO₂ emissions, monthly basis

In aggregate, the results indicate that the procurement policy resulted in a reduction of CO₂ emissions of approximately 5,076 tonnes from its commencement in 2006 through to June 2011. These are the CO₂ emissions that were abated as a result of the renewable energy procurement programme.

4.4. Cost of CO₂ emission abatement

Having obtained estimates of the loss of total surplus related to the regulator's programme of generation procurement, as well as estimates of the amount of CO₂ emissions thereby abated, the cost of CO₂ emission abatement can be estimated using equation (III-9). A modified version of equation (III-9) can be used in which the loss of surplus is the loss of surplus attributable to Ontario-based consumers alone rather than that of all economic agents combined.

Table III-5 reports the mean and standard deviation of CO₂ emission-abatement costs using total surplus and Ontario-based consumers' surplus alone as the relevant social cost based on the assumption that it is natural gas-fuelled generation that replaces renewable energy under the counterfactual policy. Given that there was no CO₂ emission-abatement before the first renewable energy generator entered the market in March 2006, equation (III-9) is not meaningfully defined for all 110 months of the study period. It is, therefore, calculated only for the 64 months in which renewable energy generators were in the market. The statistics are presented for all 64 months in which equation (III-9) can be calculated and the last 24 months only. Figure III-18 illustrates CO₂ emission-abatement costs for both definitions of social cost for all relevant months.

Table III-6 and Figure III-19 report analogous results based on the assumption that it is coal-fuelled generation that replaces renewable energy under the counterfactual policy.

*Table III-5: Cost of CO₂ emission-abatement
Dollars per tonne of CO₂ (\$/tonne)
Renewable energy in place of natural gas
Based on total surplus and Ontario-based consumers' surplus alone
All months and last 24 months*

Measure of surplus	All Months		Last 24 Months	
	Mean	Std. Dev.	Mean	Std. Dev.
Total surplus	205.21	43.78	236.00	39.69
Ontario-based consumers' surplus	132.83	45.12	168.68	38.55

*Table III-6: Cost of CO₂ emission-abatement
Dollars per tonne of CO₂ (\$/tonne)
Renewable energy in place of coal
Based on total surplus and Ontario-based consumers' surplus alone
All months and last 24 months*

Measure of surplus	All Months		Last 24 Months	
	Mean	Std. Dev.	Mean	Std. Dev.
Total surplus	92.11	19.65	105.92	17.81
Ontario-based consumers' surplus	59.62	20.25	75.71	17.30

Under the assumption that renewable energy generators produced electricity that replaced natural gas-fuelled generation, the results indicate that the average cost of CO₂ emission-abatement as a result of the regulator's programme was approximately \$205.21 per tonne of CO₂. The slight upward-movement of this cost through time is likely a result of the slight upward-movement of the average contract price of renewable generation, as illustrated in Figure III-3, to which the regulator is party. Approximately two-thirds of this cost (\$132.83 out of \$205.21 per tonne) is borne by Ontario-based consumers through a reduction of surplus resulting from the higher all-in price that prevails as a result of the programme. Notwithstanding this, the cost borne by the other economic agents is meaningful (\$72.38 per tonne), indicating that failing to

Figure III-18: Cost of CO₂ emission-abatement with renewable energy in place of natural gas

Figure III-19: Cost of CO₂ emission-abatement with renewable energy in place of coal

adequately account for the impact of the procurement programme on agents other than Ontario-based consumers will result in cost estimates that are too low.

Under the alternative assumption that renewable energy generators produced electricity that replaced coal-fuelled generation, the results indicate that the average cost of CO₂ emission-abatement as a result of the regulator's programme was approximately \$92.11 per tonne of CO₂. As under the former assumption, the slight upward-movement of this cost through time is likely a result of the slight upward-movement of the average contract price of renewable generation to which the regulator is a party. Approximately two-thirds of this cost (\$59.62 out of \$92.11 per tonne) is borne by Ontario-based consumers through a reduction of surplus resulting from the higher all-in price that prevails as a result of the programme. As under the former assumption, the cost borne by the other economic agents is meaningful (approximately \$32.49 per tonne) which indicates the importance of accounting for it.

To be clear, the analysis conducted thus far estimated the cost—a point estimate—of CO₂ emission-abatement for each month of the study period. The reported means in Tables III-5 and III-6 are the averages of these monthly values under the specified conditions. The standard deviation that is also reported measures the variability of these monthly values. While this is a useful measure of the stability of the monthly point estimates, it cannot be used to establish a confidence set around the point estimate. An alternative process that can achieve such an outcome is discussed in the next section.

4.5. Bootstrapping the cost of CO₂ emission-abatement

In order to establish confidence in the estimates of the cost of CO₂ emission-abatement associated with Ontario's generation procurement programme, it would be useful to generate standard errors associated with the point estimates rather than point estimates

alone. The process implemented in the previous sections did not allow for this outcome. However, the process can be used to construct the desired standard errors.

The results reported in the previous section are based upon using all 110 observations of market outcomes to estimate the model introduced in chapter II and subsequently the hypothetical impact on the modelled base case of a counterfactual policy under which no renewable energy generators entered Ontario's electricity market. A single point estimate of the cost of CO₂ emission-abatement was calculated.

Alternatively, the procedure described above could be repeatedly implemented using a bootstrapped sample, *i.e.*, a sample of 110 observations with replacement from the original data set.⁶⁷ Each bootstrapped sample would result in a single point estimate of the cost of CO₂ emission-abatement (for each set of conditions such as replacement fuel, *e.g.*, coal). The resulting set of point estimates would form a distribution. The mean of this distribution which would be taken to be the point estimate of the cost of CO₂ emission-abatement and the standard deviation would be taken to be its standard error.

Table III-7 reports the point estimate and standard error of the cost of CO₂ emission-abatement for both natural gas and coal as the replacement fuel. In each case there

*Table III-7: Bootstrapped cost of CO₂ emission-abatement
Dollars per tonne of CO₂ (\$/tonne)
Renewable energy in place of natural gas or coal
Based on total surplus*

Fuel Type	Mean	Std. Error
Natural gas	207.23	17.18
Coal	93.01	7.71

⁶⁷ The bootstrap procedure repeatedly samples the data with replacement and estimates both the base case model as well as the cost of emission-abatement. A superior technique involving sampling the errors associated with the model estimated in chapter II is left as future research.

Figure III-20: Distribution of cost of CO₂ emission-abatement, in \$/tonne of CO₂ emission-abatement with natural gas as the replacement fuel

Figure III-21: Distribution of cost of CO₂ emission-abatement, in \$/tonne of CO₂ emission-abatement with coal as the replacement fuel

were 9,999 replications. The data underlying these estimates are illustrated in Figures III-20 and III-21. A sketch of a normal distribution is imposed on each figure.

The bootstrapped estimates of the cost of CO₂ emission-abatement reported in Table III-7 are similar to those reported in Tables III-5 and III-6. In particular, if natural gas is the generation fuel that renewable energy generation replaces in the supply mix, then the estimated cost of CO₂ emission-abatement is approximately \$207 per tonne. If coal is the generation fuel that is replaced in the supply mix, then the estimated cost is approximately \$93 per tonne. Both estimates are statistically significant. These are the estimates that the following discussion is based upon.

5. Discussion

The analysis contained in this chapter indicates that the average cost of CO₂ emission-abatement is at least \$93 per tonne (higher toward the end of the study period). This value assumes the electricity produced by Ontario's portfolio of wind- and solar-fuelled renewable energy generators replaces that produced by coal-fuelled generators. If instead it is assumed that the electricity produced by renewable energy generators replaces that produced by natural gas-fuelled generators then the average cost of CO₂ emission-abatement is at least \$207 per tonne (also higher toward the end of the study period).

These CO₂ emission-abatement cost estimates are consistent with estimates reported by others in the context of Ontario's electricity market. For instance, in relation to the feed-in-tariff introduced in Ontario in 2009, Dewees (2010) estimates that the specified contract prices implied a value of CO₂ emission-abatement of \$85 per tonne in the case of onshore wind-fuelled generators (which are Ontario's dominate producer of non-hydroelectric renewable energy generation) replacing coal-fuelled generation. This

compares to an estimate of \$93 per tonne (standard error = 7.71) reported in this chapter.

The channels through which these costs are incurred are important. As the analysis of changes of surplus under the counterfactual policy made clear, all groups of economic agents in the market were affected by the procurement policy. Not all of these groups, however, were adversely affected by the policy.

As the results reported in Table III-3 indicate, Ontario-based consumers, non-contracted generators, and importers were negatively affected by the policy. Ontario-based consumers were negatively affected because the all-in price they pay for electricity increased. Non-contracted generators and importers were negatively affected because the wholesale market clearing price they receive for their respective activities decreased.

Exporters, on the other hand, were positively affected by the policy. This was because the wholesale market clearing price they pay decreased.

Indeed, Table III-3 indicates that the loss of surplus attributable to non-contracted generators is greater than half the size of the loss of surplus attributable to Ontario-based consumers. It is useful to consider the nature of these generators, in particular, of their ownership. With the exception of a small number of hydroelectric generators, the non-contracted generators are owned by the provincial government through the crown corporation Ontario Power Generation (OPG).⁶⁸ Therefore, this loss of surplus constitutes a loss to the people of Ontario through their provincial government.⁶⁹

⁶⁸ These generators were fuelled largely by coal, uranium (nuclear), and water (hydroelectric).

⁶⁹ This loss can be observed in two related ways. First, the assets generate less profit for their shareholder on an on-going basis, the government of Ontario. Second, losses are capitalised in the form of reduced assets valuations.

It is critical to make clear that the loss of surplus identified above does not account for the benefits obtained by CO₂ emission-abatement. Instead, it identifies the cost of the CO₂ emission-abatement. In evaluating the programme the relevant economic question is not whether these benefits are socially valuable. They are presumed to be socially valuable. Instead, the relevant economic question with respect to evaluating the programme is whether the benefits were obtained at lowest cost, that is, whether the programme was allocatively efficient. Answering this question requires a determination of what the lowest cost policy might be.

Two possible policy constructs to which Ontario's policy can be easily compared are the European Union Emissions Trading Scheme (EU ETS) and the Regional Greenhouse Gas Initiative (RGGI). The EU ETS is a useful benchmark because of the breadth of its application, both in terms of the number of industries subject to its terms and the number of countries in which it is applicable. The RGGI is a benchmark because it imposes a cost on generators for CO₂ emissions from electricity generators in the north-eastern United States, markets which are similar to Ontario's in many ways and which routinely engage in electricity trading with Ontario.

Futures contracts for EU emission allowances trade on, among other places, the Intercontinental Exchange (ICE). Over the 2-year period ranging from April 2010 to April 2012, futures contracts for EU emission allowances have traded within a price range of €6-18 per tonne of CO₂ (approximately \$8-24). Earlier it had traded as high as €30 per tonne of CO₂ (approximately \$40).⁷⁰

⁷⁰ For current (and some historical) data on futures contract prices for EU emission allowances, see ICE's webpage at <https://www.theice.com/productguide/ProductDetails.shtml?specId=197>. For additional historical data, see Grubb *et al.* (2009).

The RGGI conducts quarterly auctions of emissions allocations. The highest observed auction market clearing price occurred in March 2009 at a price of \$3.51 per tonne of CO₂.⁷¹

Given this information, it can be concluded that the average cost of CO₂ emission-abatement in Ontario's electricity market, a minimum of \$93 per tonne of CO₂ abated, is relatively high.

6. Conclusions

This chapter reported a formal analysis of the social cost of CO₂-emission abatement under Ontario's programme of renewable energy generation capacity procurement. The reported results made clear the inadequacy of focusing on the effect of the programme on consumers alone. This necessitated the use of model of the market of the type introduced in chapter II.

The analysis concluded that the cost of CO₂-emission abatement under Ontario's programme is well in excess of the cost of CO₂-emission abatement in other jurisdictions and industries. This indicates that the same CO₂-emission abatement achieved in Ontario could have been achieved at substantially lower cost—or substantially greater CO₂-emission abatement could have been achieved at the same cost—under alternative policy constructs that exist elsewhere.

⁷¹ Historical RGGI auction market data is available at http://www.rggi.org/market/co2_auctions/results.

Chapter IV: Application of global adjustment to exports

1. Introduction

There are many additional counterfactual policies that could be considered in the context of Ontario's electricity market. One that has received some attention in recent years relates to the potential application of global adjustment (GA) to exports. As described in chapter II, Ontario's current cost allocation mechanism is to apply GA only to consumers located in Ontario, *i.e.*, Ontario-based demand.

Out-of-market top-up payments made by the regulator to generators are a critical component of generators' revenue. These payments, which are funded through the global adjustment mechanism (GAM), are part of the cost associated with providing electricity to consumers. While current practice is to not levy the GA against traders who intend to export the electricity they purchase, there is no fundamental economic reason why these consumers should avoid bearing any of burden associated with these costs. A variety of alternative cost allocation rules are feasible; a subset of which will be considered here.

The chapter proceeds as follows. Section 2 discusses the motivation for and importance of considering this issue. The theoretical impact of the counterfactual policy is described in detail in section 3. Using this as a basis of analysis, section 4 reports counterfactual results, which are then described—in their own right and in relation to the base case constructed in chapter II—in section 5. Section 6 concludes.

2. Importance of issue and motivation of analytical approach

This section describes the importance of studying alternative cost allocation mechanisms, with particular focus on their treatment of exports. The general approach

taken to consider the impact of alternative mechanisms is then described.

2.1. Importance of issue

As discussed in chapters II and III, the regulator's activities have had the effect, *inter alia*, of lowering the wholesale market clearing price below the level that would have otherwise prevailed. Since exporters of electricity pay the wholesale market clearing price for their purchases, the implication is that regulator's activities induce a greater quantity of exports than would have otherwise prevailed. Indeed, a slight upward trend of the volume of exports is observable in Figure II-5.

Moreover, the GAM exists because the revenue obtained by electricity generators in the wholesale market can be insufficient to satisfy the cost recovery guarantees made by the regulator to certain contracted generators. The revenue obtained from consumers through the GAM funds the balance of these payments and constitutes part of total cost. There is no economic rationale for exempting certain consumers from cost recovery considerations simply because of the location of consumption.

A number of alternative GA cost allocation mechanisms will be considered that depart in various ways from exempting exports from the GA altogether. Investigating the characteristics of these mechanisms is the purpose of this chapter. Among other effects is the possibility that subjecting exports to the GA may at least partially counteract the impact of the regulator's activities on exports of electricity.

2.2. Motivation of analytical approach

Under a counterfactual policy in which the pricing treatment of exports differs from current practice, the level of exports will differ from that observed under current practice. This, in turn, would impact the wholesale market equilibrium, including the wholesale market clearing price, the GA rate, the all-in price, and the levels of Ontario-

based supply, imports, and Ontario-based demand. The model developed and reported in chapter II can be used to determine the impact of a policy change on each of these values.

Having determined the impact on each of the variables listed — the ones determined within the model described in chapter II — the amount by which total surplus differs under the counterfactual policy in comparison to the base case can be determined. Surplus is obtained by each of four types of economic agents considered: consumers based in Ontario (Ontario-based demand), producers based in Ontario (Ontario-based supply), and inter-jurisdictional traders (importers and exporters). The impact of the counterfactual policy on each of these groups of agents must be considered.

(The descriptions that follow of the impact of the counterfactual policy on the surplus obtained by each group of economic agents are similar to those given in section 2.2 of chapter III.)

Ontario-based consumers pay the all-in price, which is the sum of the wholesale market clearing price and the GA rate. The impact of the counterfactual policy need not have symmetric effects on the components of this price. That is, one component could increase while the other decreases. Since Ontario-based consumers pay both, it is the net impact of the counterfactual policy that is relevant to consumers. A change of the all-in price, therefore, impacts consumers' surplus. The effects of the individual components of the all-in price on consumers are not considered.

Ontario-based producers face incentives that are not uniform across all firms. Firms that operate under contracts with the regulator are not affected by the counterfactual policy as they are compensated for any change of the wholesale market conditions. Other firms are exposed to the wholesale market clearing price. For these firms, a change of the wholesale market clearing price impacts the surplus they obtain.

Importers of electricity are paid the wholesale market clearing price and are impacted by the counterfactual policy in a manner analogous to non-contracted Ontario-based producers.

The last group of economic agents considered is exporters of electricity. Under a counterfactual policy in which such consumers were charged the GA rate—or some fraction thereof—a wedge would be created between the wholesale market clearing price and the price paid by exporters (which would be the wholesale market clearing price plus the fraction of the GA levied against them). This would create a situation analogous to that faced by Ontario-based consumers. With respect to the surplus obtained by exporters, it would be impacted if the exporters' price differs from the original wholesale market clearing price.

The change of total surplus associated with the counterfactual policy under which an alternative GA cost allocation rule is adopted is the sum of the individual effects outlined above.

The changes of surplus, both at the level of the economic agents themselves and in aggregate, associated with the counterfactual policy can be used to inform a discussion about the treatment of exports of electricity in a cost allocation context. There are a variety of perspectives—which define particular counterfactual policies—that could be taken in the associated analysis, some of which will be discussed here. The first is pro rata application of the GA rate to exports, in which case exports are treated in the same manner as consumption by Ontario-based consumers. The second is to levy the GA at a rate that maximises total surplus or, equivalently, maximises the change in total surplus relative to the case (current policy) in which GA is not levied against exports. The third is to levy the GA at a rate that maximises the surplus of Ontario-based consumers, which is equivalent to minimising the all-in price.

Finally, since exporters are charged some positive amount of GA under the counterfactual policy, the regulator would receive revenue from these transactions. The regulator's budget constraint must reflect this second source of revenue (in addition to the revenue generated by levying the GA on Ontario-based consumers).

With results associated with each of these counterfactual policies having been obtained, an assessment of the current GAM's treatment of exports can be undertaken.

3. Analytical approach and anticipated effects

The counterfactual policy impacts the market through two mechanisms: by altering the export demand equation and by altering the regulator's budget constraint. The previous section described each of these mechanisms in general terms. A detailed description focusing on how they affect the model introduced in chapter II is provided here.

Section 3.1 describes how the counterfactual equilibrium is explicitly modelled in the model introduced in chapter II. Section 3.2 inventories the set of particular cost allocation rules—special cases of the general counterfactual equilibrium considered in section 3.1—considered in this chapter.

3.1. Counterfactual equilibrium

The GA rate (g_t), or any fraction thereof, could be charged to exports as well as Ontario-based demand. Define this fraction to be z . It is assumed to be time-invariant. Thus, the exporters' price would be $p_t + zg_t$.

Under the counterfactual policy, the first mechanism identified above requires that the export demand equation—equation (II-4)—be re-specified to reflect the altered price

charged to exports. Thus, the export demand equation under the counterfactual policy is

$$q_t^e = \beta_0 + \beta_1(p_t + zg_t) + \beta_2NY_L_t + \varepsilon_{4t} \quad (IV-1)$$

The second mechanism requires that the equation that specifies the revenue collected by the regulator—equation (II-5)—be re-specified to account for the revenue associated with the level of exports. Thus, the amount of revenue collected by the regulator is

$$Rev_t = g_t(q_t^d + zq_t^e) \quad (IV-2)$$

As a result of this re-specification, the regulator's budget constraint changes as well. Given that the costs borne by the regulator—specified by equations (II-6) and (II-7)—are not affected by the counterfactual policy, the regulator's budget constraint becomes

$$\begin{aligned} g_t(q_t^d + zq_t^e) = & q_t^{wind} * (p_c^{wind} - P_t) + q_t^{solar} * solar_capacity * (p_c^{solar} - P_t) \\ & + q_t^{nugs} * (p_c^{nugs} - P_t) + q_t^{nuclear} * (p_c^{nuclear} - P_t) \\ & + q_t^{base_hydro} * (p_c^{base_hydro} - P_t) \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (IV-3)$$

The other four equations in the six-equation system of equations introduced in chapter II—Ontario-based supply (equation (II-1)), imports (equation (II-2)), Ontario-based demand (equation (II-3)), and the quantity equilibrium (equation (II-9))—are unaffected by the counterfactual policy.

The current practice of not charging the GA to exports is the special case where $z = 0$. Clearly no revenue associated with the level of exports would be collected by the regulator under such circumstances. This was referred to as the base case in the model introduced in chapter II.

Before proceeding with a discussion of the impact of the counterfactual policy on the surplus obtained by the various groups of economic agents, consider the impact on the market equilibrium of setting $z > 0$. Starting from $z = 0$, consider the effect on the magnitude of exports as captured by export demand equation (either of equations (II-4) and (IV-1)). *Ceteris paribus*, an increase in the price charged to exports would result, as reported in Table II-3-Panel D⁷², in a reduction of the quantity of electricity exported. A reduction of export demand would result in a reduction of aggregate demand and, therefore, the wholesale market clearing price. Since both Ontario-based supply and imports have been found to respond positively to an increase in the wholesale market clearing price, as reported in Table II-3-Panels A and B⁷³, a reduction of the wholesale market clearing price will reduce both. Ontario-based demand, as reported in Table II-3-Panel C⁷⁴, will increase.

The impact described above assumed all else was equal. This is not the case, however. In particular, the GA rate, as it is endogenous with respect to the wholesale market, may change as well. To consider how the GA rate changes, if at all, assume it does not change. With the GA rate held constant, increased Ontario-based demand results in additional revenue being collected by the regulator as described by equation (IV-5). As well, as long as exports do not decline to zero, additional revenue for the regulator is collected from them. Overall, the regulator's revenue increases. However, a lower wholesale market clearing price results in Ontario-based suppliers earning less revenue from the wholesale market. As summarised by equation (IV-3), many Ontario-based suppliers operate under contracts that entitle them to receive specified out-of-market top-up payments that are inversely related to the wholesale market clearing price.

⁷² It is reported in the table that $\hat{\beta}_1 = -21.71 < 0$, a statistically significant result (p-value = 0.000).

⁷³ It is reported in the table that $\hat{\gamma}_1 = 110.12 > 0$ and $\hat{\delta}_1 = 20.29 > 0$, both statistically significant results (p-value = 0.000 for each).

⁷⁴ It is reported in the table that $\hat{\alpha}_1 = -84.55 < 0$, a statistically significant result (p-value = 0.000).

Taken together, the effect of these contracts is to raise the amount of expenses incurred by the regulator. The net impact on the regulator's budget is ambiguous.

On the other hand, since only a subset of Ontario-based suppliers is subject to receiving out-of-market top-up payments that constitute an expense for the regulator, the total amount of revenue collected by suppliers from all sources declines. Since Ontario-based demand increases, the all-in price charged to Ontario-based consumers declines. Therefore, a potential increase of the GA rate is of a smaller absolute magnitude than the decrease of the wholesale market clearing price.

In sum, the theoretical impact of the application of GA to exports in comparison to the base case under which no GA is applied to exports is to reduce exports, imports, and Ontario-based supply as well as both the wholesale market clearing and all-in prices, while increasing Ontario-based demand and the price paid for exports. The impact on the GA rate itself is ambiguous. With respect to the quantity equilibrium, the decrease in exports is offset by the increase of Ontario-based demand and the decrease of Ontario-based supply and imports.⁷⁵

The impact on each of the endogenous components of the market equilibrium—the four quantities and two prices—will change with a changing z . The fundamental feature of an increasing z is that the price charged to exports will rise continuously, thereby reducing the level of exports continuously. At some level of z a policy of levying GA on exports becomes counter-productive for Ontario-based consumers as the quantity of exports decline sufficiently such that the all-in price paid by Ontario-based demand begins to rise. Moreover, at some level of z the model will become unstable due to, for instance, exports violating the non-negativity constraint. It is not obvious that these

⁷⁵ Note that Ontario-based supply plus imports is strictly greater than Ontario-based demand plus exports as a result of line losses.

issues are relevant over the range of z that is of interest here—a range that is discussed below—but will be revisited with the presentation of the results below.

3.2. Cases considered

A number of alternative GA allocation rules are of particular interest here. Each of these can be thought of as special cases of the counterfactual policy. In particular, each can be associated with a particular level of z . First, pro rata application of GA to exports implies $z = 1$. Second, z could be selected so as to maximise total surplus. Third, z could be selected so as to maximise the surplus of Ontario-based consumers. This is equivalent to minimising the all-in price. Each of these rules is discussed in detail.

Determining the counterfactual policy equilibrium in the case where GA is applied to exports on a pro rata basis is the most straightforward of the four cases to be considered in detail. In particular, $z = 1$ implies that the export price and the all-in price both equal to $p_t + zg_t = p_t + g_t$. Likewise, equations (IV-1) and (IV-2) become

$$q_t^e = \beta_0 + \beta_1(p_t + g_t) + \beta_2 NY_L_t + \varepsilon_{4t} \quad (IV-4)$$

and

$$Rev_t = g_t(q_t^d + q_t^e) \quad (IV-5)$$

Finding the counterfactual policy equilibrium can be done in a manner comparable to the process used to solve for the base case equilibrium in chapter II. The impact of pro rata application of GA to exports is defined to be the difference between these two equilibria.

Determining the particular value of z that maximises total surplus requires that the components of total surplus under each value of z be computed. Equivalently, the magnitude of surplus obtained by each group of economic agents over the range of z

values considered can be compared to a reference case, say $z = 0$ —the base case constructed in chapter II. For each value of z , the deviation of total surplus from that obtained under the base case is defined to be the change of surplus associated with z . Choosing z so as to maximise this difference yields the particular rate at which application of GA to exports maximises total surplus. The process used to make these change of surplus calculations is analogous to the process used to calculate the changes of surplus associated with the no renewable energy counterfactual policy studied in detail in chapter III. See section 3.2 of chapter III for an extended discussion.

Finally, determining the particular value of z that maximises the surplus obtained by Ontario-based consumers can be done by following a process identical to that used when maximising total surplus.

It was stated above that attention would be focused on a particular range of z values. Negative values of z imply either: (i) contemporaneous rebates to exports and charges to Ontario-based demand or (ii) contemporaneous charges to exports and rebates to Ontario-based demand. Thus, negative values of z are ignored. As a result, the range considered is $z \geq 0$.

4. Empirical results

This section reports the empirical results associated with implementation of the analytical approach described in the previous section. Section 4.1 reports the counterfactual policy equilibrium under various values of z , while section 4.2 uses these results to determine the particular values of z associated with the third and fourth cases of particular interest discussed in section 3.2.

4.1. Counterfactual equilibrium

The counterfactual policy equilibrium is constructed for values of $z > 0$, at z -increments of 0.01.⁷⁶ Each equilibrium is characterised by values of the six endogenously-determined variables—Ontario-based supply, imports, Ontario-based demand, exports, the wholesale market clearing price, and the GA rate (and by extension, the all-in price and the exporters' price)—as well as the amount by which the surplus obtained by each of the four groups of economic agents differs from the base case.

Table IV-1 reports the mean and standard deviation of each of the endogenous variables in the model under the base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports. The statistics are presented for all 110 months of the study period and the last 24 months only. Figure IV-1 illustrates the wholesale market clearing price time series corresponding to these two cases for the whole study period. Similarly, Figures IV-2 and IV-3 illustrate the GA rate and all-in price time series, respectively. It is the mean and standard deviation of these series that are summarised in Table IV-1.

Figure IV-4 separately illustrates the mean of the counterfactual policy wholesale market clearing price, GA rate, Ontario all-in price, and export price for values of z ranging from 0 to 1 at one-hundredth increments, respectively. Similarly, Figure IV-5 illustrates the mean of the counterfactual policy wholesale market clearing price, Ontario all-in price, and export price on a single plot, while Figure IV-6 separately illustrates the mean of the counterfactual policy Ontario-based supply, imports, Ontario-based exports, and exports, respectively. All 110 months of data were used in the calculation of these figures.

⁷⁶ $z = 0$ is not a counterfactual since it is the base case. The results reported in the case where $z = 0$ are, therefore, the same as those reported in chapter II as the base case.

Table IV-1: Endogenous variables under base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual, all months and last 24 months
Units defined in Table II-1

Variable	Case	All Months		Last 24 Months	
		Mean	Std. Dev.	Mean	Std. Dev.
q_t^s	Base Case	17,570.2	1,129.6	17,583.2	1,182.9
	GA Export	17,490.6	1,165.8	17,325.0	1,243.6
q_t^i	Base Case	949.0	306.3	655.8	195.9
	GA Export	934.3	324.4	608.2	214.5
q_t^d	Base Case	16,685.5	1,168.4	16,263.8	1,303.0
	GA Export	16,745.5	1,117.6	16,455.8	1,238.6
q_t^e	Base Case	1,370.7	459.6	1,519.2	217.1
	GA Export	1,218.8	467.3	1,029.1	199.4
p_t	Base Case	49.83	11.91	37.46	11.05
	GA Export	49.11	12.99	35.12	12.06
g_t	Base Case	7.71	12.77	24.85	11.38
	GA Export	7.72	12.76	24.92	11.34
$p_t + g_t$	Base Case	57.54	5.09	62.31	1.87
	GA Export	56.83	4.81	60.04	2.01

For each of the four groups of economic agents under consideration, Figure IV-7 illustrates the mean change in surplus obtained under the counterfactual policy z relative to the reference case, $z = 0$. Thus, the change in surplus obtained at $z = 0$ —the base case—is, by definition, zero. Values of z ranging from 0 to 1 are illustrated.

Figure IV-8 illustrates the mean change in surplus obtained under the counterfactual policy z relative to the reference case for Ontario-based consumers alone over a larger range of z values than considered in Figure IV-7.

Finally, Figure IV-9 illustrates the change in total surplus obtained by all economic agents collectively under the counterfactual policy z relative to the base case. The illustrated curve is the vertical sum of the four curves illustrated in Figure IV-7—over

Figure IV-1: Wholesale market clearing price time series
Base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual

Figure IV-2: Global adjustment time series
Base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual

Figure IV-3: All-in price time series
Base case ($z = 0$) and pro rata ($z = 1$) application of GA to exports counterfactual

Figure IV-4: Wholesale market price, GA rate, Ontario all-in price, and export price, various z

Figure IV-5: Wholesale market clearing price, Ontario all-in price, and export price, various z

Figure IV-6: Ontario-based demand, exports, Ontario-based supply, and imports, various z

Figure IV-7: Change of surplus, by group of economic agents at various values of z

Figure IV-8: Change of surplus of Ontario-based consumers at various values of z

Figure IV-9: Change of total surplus at various values of z

the same range of z values.

The data illustrated in Figures IV-7, IV-8, and IV-9 are denominated in dollars. Since it is a typical hour that is modelled, the changes in surplus can be interpreted as changes in dollars of surplus per hour.

4.2. Cases considered

As described in section 3.2, three alternative GA allocation rules are assessed in this chapter in terms of their treatment of electricity exports. The first, pro rata application of the GA rate to exports, is defined as an explicit value of z , *i.e.*, $z = 1$. The second and third rules require an analysis of the magnitude of surplus obtained by the various groups of economic agents.

The particular value of z that maximises the total surplus obtained by all economic agents jointly is illustrated in Figure IV-9. It is $z = 0.32$. This result means that allocating GA to exports at 32% of the rate at which it is applied to Ontario-based consumption maximises total surplus. This result is consistent—in the sense of a classic Ramsey-inspired allocation rule—with the finding in chapter II that the price elasticity of Ontario-based demand is approximately one-third that of demand for exports.

The particular value of z that maximises the surplus obtained by Ontario-based consumers alone is illustrated in Figure IV-8. It is $z = 1.56$. This result means that allocating GA to exports at 156% of the rate at which it is applied to Ontario-based consumption maximises the surplus obtained by consumers located in Ontario. It is particularly notable that this allocation rate exceeds unity, a finding commented on in the next section.

It is not surprising that this allocation rate is greater than the rate that maximises total surplus. To see why, from an initial allocation rate of $z = 0.32$, consider the effect on the wholesale market equilibrium of raising z —the reasoning of which is similar to that of $z > 0$ compared to $z = 0$ as explained above. An increase of the allocation rate will result in a higher export price and, therefore, fewer exports (Figures IV-5 and IV-6, respectively). The decline in exports constitutes a decline in aggregate demand and, therefore, the wholesale market clearing price (Figure IV-4). Imports and Ontario-based supply would also decline (Figure IV-6). The impact on the GA rate itself is, as discussed above, more complex to unravel, with the effect being ambiguous. However, the results illustrated in Figure IV-4 show that an increase of the allocation rate z above 0.32 lowers the all-in price paid by consumers located within Ontario, thereby raising the surplus obtained by them (Figure IV-8). Thus, the allocation rate that maximises the surplus obtained by Ontario-based consumers alone is greater than the rate that maximises total surplus.

5. Discussion

A discussion of the counterfactual policy results associated with each of the three alternative GA allocation rules described above is reported in this section.

5.1. Pro rata ($z = 1$)

Table IV-1 reports that, averaged over (i) all 110 months of the study period and (ii) the last 24 months of the study period, the counterfactual policy impact of pro rata application of GA to exports (compared to the base case) would be to reduce exports, Ontario-based supply, imports, the wholesale market clearing price, and the Ontario all-in price, while increasing Ontario-based demand. These directional results accord with the theoretical expectations described in section 3.1. The GA rate itself, which was anticipated to be ambiguously affected by the counterfactual policy, is found to be impacted (marginally) positively.

In particular, over the whole study period, the results report that pro rata application of GA to exports reduces the average wholesale market clearing price by \$0.72 per MWh, from \$49.83 per MWh to \$49.11 per MWh, a reduction of approximately 1.4%. The GA rate itself is reported to increase by \$0.01 per MWh, from \$7.71 per MWh to \$7.72 per MWh, an increase of approximately 0.1%. The Ontario all-in price—the wholesale market clearing price plus the GA rate—is reported to decline by \$0.71 per MWh, from \$57.54 per MWh to \$56.83 per MWh, a reduction of approximately 1.2%. These results confirm the expectation described in section 3.1 that the magnitude of the GA rate change is smaller than the magnitude of the wholesale market clearing price change.

With respect to the quantities, pro rata application of GA to exports reduces the average volume of exports by approximately 152 MWh per hour, or 11.1%. Ontario-based demand increases by 60 MWh per hour (0.4%), while Ontario-based supply and imports

decline by 80 MWh per hour (0.5%) and 15 MWh per hour (1.5%), respectively.⁷⁷

The data reported in Table IV-1, among other things, include averages of the time series illustrated in Figure IV-1, IV-2, and IV-3, for the two time periods indicated. It is evident from the figures that the impact of pro rata application of GA to exports is relatively larger towards the end of the study period. This is not surprising, as it reflects the growing importance through time of the regulator's policy of generation procurement. This feature of the market is why Table IV-1 reports counterfactual policy results for the last 24 months of the study period.

Over the last 24 months of the study period, pro rata application of GA to exports reduces the average wholesale market clearing price by \$2.34 per MWh, from \$37.46 per MWh to \$35.12 per MWh, a reduction of approximately 6.2%. The GA itself is reported to increase by \$0.07 per MWh, from \$24.85 per MWh to \$24.92 per MWh, an increase of approximately 0.3%. The Ontario all-in price is reported to decline by \$2.27 per MWh, from \$62.31 per MWh to \$60.04 per MWh, a reduction of approximately 3.6%. As with the results corresponding to the whole study period, these results confirm the expectation that the magnitude of the GA rate change is smaller in magnitude than the magnitude of the wholesale market clearing price change.

With respect to the quantities, pro rata application of GA to exports reduces the average volume of exports by approximately 490 MWh per hour, or 32.3%. Ontario-based demand increases by 193 MWh per hour (1.2%), while Ontario-based supply and imports decline by 258 MWh per hour (1.5%) and 48 MWh per hour (7.3%), respectively.⁷⁸

⁷⁷ Due to assumed line losses and rounding, the changes of the endogenous quantities do not net out to zero. This is analogous to the impact of line losses on the quantity equilibrium condition, equation (II-9).

⁷⁸ See the previous footnote.

With respect to the impact on total surplus and its components across the whole study period, pro rata application of GA to exports would decrease the surplus obtained by non-contracted Ontario-based supply and importers (because the wholesale market clearing price would be lower), as well as that obtained by exporters (because the export price would be lower). In particular, average hourly surplus obtained by Ontario-based supply, importers, and exporters would be approximately \$3,058, \$401, and \$8,899, lower under the counterfactual policy, respectively. The surplus obtained by Ontario-based consumers would be \$11,176 higher per hour. These values are illustrated in Figures IV-7 and IV-8. In sum, hourly total surplus would be \$1,182 lower under the counterfactual policy.⁷⁹ On an annual basis, total surplus would be approximately \$10.4 million (= \$1,182 per hour * 8,760 hours per year) lower under the counterfactual policy compared to the base case.

It is evident from the results presented in Table IV-1, as well as Figure IV-6, that the impact of pro rata application of GA to exports would meaningfully reduce the volume of exports—by 11.1% over the whole study period. It is also evident that such a policy would have had a relatively large impact towards the end of the study period, underscoring the growing importance of the GA rate component of the all-in price paid by Ontario-based demand. While pro rata application of GA to exports would be beneficial to consumers located within Ontario, all other groups of economic agents considered would lose surplus as a result. As well, society as a whole would be worse off as total surplus would be reduced.

These results suggest that pro rata application of GA to exports is not an economically desirable policy option. The policy is not optimal from the perspective of society as a whole and, while consumers located in Ontario would be made better off, the policy is

⁷⁹ Figures do not sum correctly due to rounding.

not necessarily optimal from their perspective either (as will be shown below).

Discussions with current and former senior officials at the IESO support the conclusion that pro rata application of GA to exports would not be a desirable policy choice for Ontario. In particular, given that towards the end of the study period the GA rate regularly exceeded the wholesale market clearing price, it has been stated that based upon based upon their best judgement, informed by experience, pro rata application of GA to exports may cause exports to fall to zero—especially during off-peak hours.

5.2. Maximum total surplus

In the previous section it was shown that pro rata application of GA to exports resulted in less surplus being obtained by all economic agents together compared to the base case, *i.e.*, $z = 1$ is socially preferable to $z = 0$. However, it is possible that there exists at least one allocation rate $z > 0$ that differs from unity and yields more total surplus than $z = 0$. In fact, the results illustrated in Figure IV-9 show those allocation rates $0 < z < 0.63$ create more total surplus than $z = 0$, with total surplus being maximised with $z = 0.32$.

The wholesale market equilibrium under the counterfactual policy where $z = 0.32$ can be read off Figures IV-4, IV-5, and IV-6. In particular, the average wholesale market clearing price would be \$49.64 per MWh, a reduction of \$0.19 per MWh (0.4%) compared to the base case average of \$49.83 per MWh; the average GA rate would be \$7.61 per MWh, a reduction of \$0.10 per MWh (1.3%) compared to the base case average of \$7.71 per MWh; the average all-in price would be \$57.25 per MWh, a reduction of \$0.29 per MWh (0.5%) compared to the base case average of \$57.54 per MWh; and the average export price would be \$52.07 per MWh ($= 49.64 + 0.32 * 7.61 = 49.64 + 2.34$), an increase of \$2.24 per MWh (4.5%) compared to the base case average of \$49.83 per MWh.

The average level of Ontario-based demand would be 16,710 MWh per hour, an increase of 24 MWh per hour (0.1%) compared to the base case average of 16,686 MWh per hour; the average level of exports would be 1,322 MWh per hour, a decrease of 48 MWh per hour (3.5%) from the base case average of 1,370 MWh per hour; the average level of Ontario-based supply (from all sources) would be 17,549 MWh per hour, a decrease of 21 MWh per hour (0.1%) compared to the base case average of 17,570 MWh per hour; and the average level of imports would be 945 MWh per hour, a decrease of 4 MWh per hour (0.4%) from the base case average of 949 MWh per hour. Note that due to line losses (equation II-9)), the quantity changes, like the totals, do not net to zero.

Total surplus would increase by an average of \$320 per hour under the counterfactual policy of $z = 0.32$. Annualised, this is equivalent to \$2.8 million ($= \$320 \text{ per hour} * 8760 \text{ hours per year}$). This is, by definition, the maximum possible increase in total surplus. However, the four groups of economic agents are not impacted symmetrically. In fact, Ontario-based consumers would be the only group that benefits, with the surplus obtained by them increasing by an average of \$4,525 per hour or, equivalently, \$39.7 million per year. The other three groups would lose surplus. Exporters would lose the most: an average of \$3,287 per hour or, equivalently, \$28.8 million per year. Non-contracted Ontario-based supply and importers would lose an average of \$807 per hour (\$7.1 million per year) and \$111 per hour (\$1.0 million per year), respectively.

In summary, allocating GA to exports at 32% of the rate at which it is applied to Ontario-based consumers maximises the level of total surplus obtained. In particular, annual total surplus would average approximately \$2.8 million more than under the base case. Moreover, annual total surplus would average approximately \$13.2 million ($= 2.8 + 10.4$) more than under pro rata application of GA to exports.⁸⁰

⁸⁰ \$13.2 million is the sum of \$2.8 million and \$10.4 million.

These results suggest that of the three allocation rules considered thus far — $z = 0$, 0.32 , and $1 - z = 0.32$ is the most preferred allocation, followed by $z = 0$ and then $z = 1$.

5.3. Maximum Ontario consumers' surplus

The final GA allocation rule to be considered is the one that would maximise the amount of surplus obtained by Ontario-based consumers alone. As stated in section 4.2, the allocation rate that would accomplish this outcome is $z = 1.56$. In other words, allocating the regulator's costs to exports at 156% of the rate at which they are allocated to Ontario-based consumers would maximise the surplus obtained by said consumers.

So as to focus on the rule that maximises total surplus, Figures IV-7 and IV-9 do not illustrate the rule under consideration here. However, the change in surplus obtained by Ontario-based consumers under the counterfactual policy $z = 1.56$ can be read-off of Figure IV-8. It averages \$13,497 per hour. Annualised, this is equivalent to \$118.2 million per year.

The corresponding wholesale market equilibrium under the counterfactual policy would be as follows. The wholesale market clearing price would be \$48.44 per MWh, a reduction of \$1.39 per MWh (2.8%) compared to the base case average of \$49.83 per MWh; the average GA rate would be \$8.25 per MWh, an increase of \$0.54 per MWh (7.0%) compared to the base case average of \$7.71 per MWh; the average all-in price would be \$56.68 per MWh, a reduction of \$0.86 per MWh (1.5%) compared to the base case average of \$57.54 per MWh; and the average export price would be \$61.30 per MWh ($= 48.44 + 1.56 * 8.25 = 49.64 + 12.87$), an increase of \$11.47 per MWh (23.0%) compared to the base case average of \$49.83 per MWh.

The average level of Ontario-based demand would be 16,758 MW, an increase of 72 MW (0.4%) compared to the base case average of 16,686 MW; the average level of exports

would be 1,122 MW, a decrease of 248 MW (18.1%) from the base case average of 1,370 MW; the average level of Ontario-based supply (from all sources) would be 17,417 MW, a decrease of 153 MW (0.9%) compared to the base case average of 17,570 MW; and the average level of imports would be 921 MW, a decrease of 28 MW (3.0%) from the base case average of 949 MW. Note that due to line losses (equation II-9)), the quantity changes, like the totals, do not net to zero.

While the surplus obtained by consumers located in Ontario would rise by an average of \$13,497 per hour, or equivalently, \$118.2 million per year under the counterfactual policy, the three other groups of economic agents would be made worse off. Exporters would lose the most: an average of \$12,485 per hour or, equivalently, \$109.4 million per year. Non-contracted Ontario-based supply and importers would lose an average of \$5,895 per hour (\$51.6 million per year) and \$722 per hour (\$6.3 million per year), respectively. Taken together, total surplus would decline by an average of \$5,605 per hour or, equivalently, \$49.1 million per year.

It is important to note that this rule ignores the surplus people would obtain indirectly, through ownership of electricity trading (importers and exporters) firms and Ontario-based producers, including crown corporations whose profit ultimately flows to the government.

In summary, allocating GA to exports at 156% of the rate at which it is applied to Ontario-based consumers maximises the surplus the said group obtains. This comes, however, at considerable cost other groups of economic agents and, in aggregate, results in the least total surplus being obtained than under either of the other two counterfactual allocation rules considered as well as the base case itself.

5.4. Comparison of alternative allocation rules

The previous sections compared the current practice of exempting exports from bearing any of the costs associated with the regulator's activities to three alternative cost allocation rules: a rule that ignores the distinction between exports and domestic consumption (the pro rata rule, $z = 1$); a rule that maximises total surplus ($z = 0.32$); and a rule that maximises the surplus obtained by Ontario-based consumers alone ($z = 1.56$).

With respect to the total surplus criterion, allocation of GA to exports at 32% of the rate at which it is allocated to Ontario-based consumers was found to be optimal. Of the other alternative allocation rules considered, the current practice of exempting exports from GA-related costs is preferable to pro rata application of GA to exports, which is itself preferred to the rule that would maximise surplus of Ontario-based consumers alone.

The reason for these differences is related to the extent to which allocation of GA to exports affects the level of exports. Charging GA to exports results in a portion of the regulator's costs—including the cost of the regulator's capacity procurement programme—being allocated to exports. The higher is the allocation rate, the greater is the effect on the level of exports. The total contribution to cost recovery on the part of exports is the product of (i) the level of exports, (ii) the GA rate, and (iii) the export allocation rate (z). Under current policy, this product is zero since $z = 0$, meaning exports currently make no contribution to the regulator's cost recovery. Choosing a relatively high export allocation rule would result in the level of exports being relatively low, implying that relatively little cost recovery would occur and that its effect would be a substantial loss of surplus that would have otherwise been obtained by traders.

Choosing the allocation rate so as to maximise total surplus does not imply that the contribution made to the regulator's costs by exports is maximised. Rather, it means

that this potential source of cost recovery is meaningful enough that it should not be ignored. Indeed, as the results presented in chapter II regarding the relative elasticity of Ontario-based demand and export demand indicate, a Ramsey-inspired allocation rule (maximisation of total surplus subject to a constraint, which in this case is the regulator's budget constraint) would suggest an allocation rate in the vicinity of one-third. This suggestion is confirmed by the counterfactual policy exercise undertaken in this chapter.

One result that is clear and corresponds with standard economic theory (especially, Ramsey pricing) is that the optimal GA allocation rule is not $z = 0$. That is, Ontario's current GA allocation policy in relation to covering the costs associated with exports is not optimal.

6. Conclusions

Based on the results reported in chapters II and III, it is argued that the regulator's procurement policy, which acted in the market by increasing the amount of supply available at each price, is at least partially responsible for the decline of the wholesale market clearing price observed throughout the study period. This shifted costs guaranteed by the regulator from being covered by wholesale market revenue to being covered by the regulator and recovered from consumers through the GA. These increased GA costs led to a general increase in the level of the GA rate charged to Ontario-based consumers who, under current policy, pay all GA-related costs. At the time of its introduction, the GA rate did not constitute a consistently positive and large proportion of the all-in price. However, the growing importance over time of the GA rate as a component of the all-in price of electricity can be interpreted as a shift away from incremental cost pricing towards average cost pricing, an outcome which has negative implications for the allocative efficiency of the wholesale market. This

development also magnifies the importance of the rule used by the regulator to allocate its costs among consumers.

The purpose of this chapter is to consider whether the current practice of not allocating any of the cost of the regulator's activities—including its programme of generation procurement—to exports is optimal or not. To that end, a set of cost allocation rules that could be used to allocate these costs differently are considered as counterfactual policies in the context of the model introduced in chapter II.

The results of the analysis indicate that an export allocation rate of 32% is optimal from the perspective of total surplus maximisation. Moreover, the results indicate that the current policy of exempting exports from GA is preferable on total surplus-maximisation grounds than either pro rata application of GA to exports or the adoption of a rule that maximises the surplus of Ontario-based consumers alone.

6.1. Future research

Future research regarding the issues discussed in this chapter could proceed in a number of different directions. Five of these are discussed in this section.

First, the range of GA allocation rules considered in this chapter is limited to specific (dollar) mark-ups of the wholesale market clearing price.⁸¹ An alternative approach would be to charge GA to consumers as a percentage mark-up, *i.e.*, an *ad valorem* rate, of the wholesale market clearing price. Such a rule could be applied to the hourly wholesale market clearing price, thereby allowing the dollar-valued GA rate to vary across the hours within a month. The shift away from incremental cost pricing towards average cost pricing would be muted as the amount of GA allocated to hours with low

⁸¹ Since the GA rate is equal across all the hours within a month, there is no difference between levying the GA rate based upon hourly or monthly consumption.

(high) wholesale market clearing prices would be lower (higher) than under a specific allocation rule.

Second, as discussed in Appendix II-A, recent changes to the GA allocation rule affecting large consumers (class A) are likely to play an increasingly important role in the consumption behaviour of these consumers and, by extension, small consumers (class B) as well. Accounting for this process will be necessary for data beyond June 2011 to be analysed. Indeed, the Market Surveillance Panel (MSP, April 2012) reports preliminary evidence that class A consumers have responded to the rule change by changing their consumption patterns in a manner that allows them to avoid some portion of GA-related expenses.⁸² As well, there is a number of interesting political economy issues associated with the design, adoption, and functioning of the new GA allocation rule that heretofore remain unaddressed.

Third, the study employs a model that uses average monthly data, thereby ignoring the role of intra-month characteristics such as the on-peak/off-peak distinction. There may be value associated with specifying a model that accounts for this distinction. With the exception of the regulator's budget constraint, which covers both on-peak and off-peak hours of the month, all the other equations in the system could have on-peak and off-peak versions.

Fourth, it was assumed that the coefficients of the various equations were stable through time, *e.g.*, the Ontario-based demand curve always has the same slope. It may

⁸² In particular, it is reported that there is some evidence that large price-sensitive (class A) consumers have shifted consumption out of peak periods in order to avoid paying GA. However, it is not clear that the process by which the counterfactual policy is constructed is sensible—a shortcoming recognised by the report itself. For instance, the data show that class A consumers pay a smaller proportion of total GA expenses than they consume of total electricity. It is not implausible to believe that this would have been the case had the previous policy remained in place. To the extent that it would have been, the difference between the proportion of GA expenses paid and electricity consumed cannot be due to the policy change.

be the case that, for instance, the various policy developments since market opening have caused structural changes that have altered the estimates of these coefficients, especially with respect to the various price terms.

Fifth, it was implicitly assumed above that application of all or part of the GA to electricity exports by Ontario would not result in any kind of retaliatory action on the part of neighbouring jurisdictions. However, external jurisdictions may perceive the GA as comparable to their own capacity market cost uplift, and might respond to its application to exports with a similar rule. While it is not clear that retaliation would be sensible from the perspective of the external jurisdiction, it is also not clear what factors would guide the decision-making associated with any response. This must be better understood before any policy change can be entertained.

Chapter V: The market for short-term financial transmission rights

1. Introduction

Along with the introduction of a wholesale market for electricity in May 2002, a market for financial transmission rights was also introduced. In 2010, the annual value of energy traded in the wholesale market, including global adjustment-related costs, exceeded \$10 billion. Wholesale market consumers pay the hourly Ontario energy price (HOEP), which is determined by an algorithm that maximizes (short-term) total surplus.⁸³ One of the principal intents of this market was to incentivise short-term productive efficiency in the supply of electricity, including imports from neighbouring jurisdictions. In the discussion that follows, attention is confined to inter-jurisdictional trade between Ontario and its neighbours, thereby ignoring intra-jurisdictional transmission issues.

Due to spatially-heterogeneous incremental costs, there exist potential gains from inter-jurisdictional trade. Traders are anticipated to arbitrage price variation between Ontario and neighbouring markets by scheduling trades appropriately. Thus, Ontario is expected to be a net importer (exporter) of electricity from (to) those neighbouring markets whose incremental costs are relatively low (high). In the absence of trade barriers, power flows would be such that electricity prices and incremental costs would equalise across jurisdictions. However, since trade of electricity occurs on a transmission grid—a network of paths that connect generators (supply, including

⁸³ Consumers pay a variety of other fees in addition to the HOEP, such as global adjustment and transmission (delivery) fees, which are ignored in this analysis. The algorithm that determines prices in Ontario ignores the impact of intra-market transmission constraints. A related algorithm that determines the physical production schedule (including imports and exports) accounts for intra-market transmission constraints. Complete descriptions of each algorithm are omitted. Also omitted is a discussion of distinction between real-time and pre-dispatch timeframes. Except in the one very limited case discussed, these details are not relevant to the following analysis.

imports) to loads (demand, including exports)—such equilibria are attainable only if the requisite power flows satisfy the physically-defined characteristics of the transmission grid, principally its flow-capacity constraints.

Ontario's transmission grid is connected to those of five neighbouring jurisdictions, namely New York, Michigan, Minnesota, Manitoba, and Quebec. The connections between jurisdictions are referred to as interties. Ontario has a single internal control zone—in which all Ontario generation and load is located—with a uniform internal price. Each of the five neighbouring jurisdictions is treated as separate external control zone with a corresponding external zone price that may differ from Ontario's internal price.⁸⁴ The extent by which any external control zone price differs (if at all) from the internal price depends on the state of congestion on the relevant transmission interface.

For each neighbouring jurisdiction, the price paid to (by) importers (exporters) is the relevant external zone price. The intertie congestion price (ICP) is defined to be the external zone price less the uniform internal price and may differ across interties. For any particular intertie, if all economically desirable energy transactions can be scheduled *without* exhausting the intertie's transmission capacity then the intertie is not congested and the internal and external zone prices must be equal. In this situation, the relevant ICP would be zero.

If the economically desirable energy transactions exhaust the intertie's capacity then the intertie is congested. A congested intertie may be import or export congested, but cannot be both simultaneously. Import congestion arises because traders seek to schedule a greater than feasible amount of imports. In this situation, allocation of scarce

⁸⁴ Technically, Ontario's electricity market is comprised of 15 zones, one of which is the internal Ontario zone. The other 14 are external zones that proxy for the five neighbouring markets: 1 for each of New York, Michigan, and Minnesota, in addition to 2 and 9 for Manitoba and Quebec, respectively. Details regarding the distinction between paths are not relevant to the following analysis.

transmission capacity is facilitated by lowering the external zone price to the level necessary so that the remaining desirable energy transactions just exhaust the intertie's capacity. Thus, import congestion results in the external zone price being less than the internal zone price, corresponding to a negative ICP. Analogously, export congestion results in the external zone price being greater than the internal zone price, corresponding to a positive ICP. In either case, the ICP is collected as revenue by the independent system operator (ISO). In Ontario, as discussed in earlier chapters, the ISO is called the Independent Electricity System Operator (IESO).

Since ICPs are determined by the interaction of supply and demand in the wholesale spot market, ex ante they are random variables from traders' point-of-view. While the spot market can be effective at incentivising short-term productive efficiency in the provision of electricity, uncertainty regarding ICPs presents a potentially significant degree of risk to traders' financial outcomes and may alter their behaviour.

Unmitigated, this risk has the potential to undermine the productive efficiency of the wholesale spot market.

Financial instruments called financial transmission rights (FTR), described in detail in the next section, have been developed to allow traders to hedge against the risk associated with uncertain congestion. The performance of these markets is, therefore, of great importance to the performance of the wholesale spot market for electricity. The principal purpose of this chapter is to assess the informational efficiency of Ontario's FTR market. Of particular interest is the extent to which forward prices in this market provide unbiased forecasts of realised congestion.

One of the most important characteristics of FTRs, discussed in greater detail in section 2, is the duration of time during which they are valid. In short, FTRs in Ontario are valid for either one month or one year. One-month FTRs are known as short-term (ST)

FTRs, while one-year FTRs are known as long-term (LT) FTRs. The analysis reported in this chapter focuses on ST FTRs exclusively. Expanding on this analysis, consideration of LT FTRs, including issues specific to them, is undertaken in chapter VI.

The chapter proceeds as follows. Section 2 provides a detailed description of the characteristics of financial transmission rights and their associated markets. Certain uncommon aspects of Ontario's market are highlighted. Readers are referred to an appendix for a detailed numerical example. Section 3 defines the meaning of an informationally efficient forward market for the purposes of this chapter and explicitly relates this definition to the concept of predictive unbiasedness. Relevant econometric approaches and issues related to the assessment of unbiasedness are also discussed. Section 4 reviews existing econometric analyses of forward market unbiasedness, especially, though not exclusively, related to FTRs. Section 5 reviews the data used in the analysis. The relative importance of two (duration) types of FTRs is discussed, and statistical analysis is undertaken for each type. Section 6 defines the econometric models estimated, hypotheses tested, and methodologies employed in the subsequent econometric analysis. Particular attention is paid to the restrictions imposed by the data on the structure of analysis undertaken. Section 7 reports discussion econometric results. Section 8 concludes.

2. Financial transmission rights

FTRs were first discussed theoretically in Hogan (1992). FTRs are financial instruments that entitle their holders to receive streams of income contingent on the degree of congestion experienced in the transmission system. In Ontario, FTRs are available only with respect to transmission lines connecting the province's internal zone to neighbouring external zones. This is related to and consistent with the province's policy of maintaining a uniform internal electricity price.

2.1. Characteristics

A particular FTR can be defined by two characteristics: duration and path. The duration characteristic defines the contiguous period of time for which the right is valid. FTRs in Ontario are valid for one of two durations: one month and one year. The path characteristic is defined in terms of two sub-characteristics: interface and direction. The interface characteristic specifies the neighbouring jurisdiction to which the right is related. In Ontario, FTRs are available for each transmission interface on which trade can be scheduled.⁸⁵ The direction characteristic specifies whether it is the import or export direction to which the right applies. Imports and exports are defined with respect to Ontario. For instance, the May 2011 New York-to-Ontario FTR is valid for each hour in May 2011 on the New York-to-Ontario path.

FTRs exist in one-megawatt (MW) increments, that is, one FTR equals one MW on a given path.

As stated previously, the ICP is defined, on an hourly basis, to be equal to the external zone price less the uniform internal Ontario price. Its value is zero, negative, or positive when there is no, import, or export congestion, respectively. The stream of income to which an FTR holder is entitled, defined analogously on an hourly basis, depends on the degree of congestion experienced on the path, and during the period of time, specified by the FTR. Each hourly payment is non-negative, while the degree of congestion is measured by the magnitude of the ICP. Consider a particular interface. If there is no congestion during an hour, payments of zero dollars are made to the holders of both the import- and export-path FTRs. If there is import-path congestion, the absolute value of the ICP—which would otherwise be negative—is paid to the holders

⁸⁵ See the previous footnote. Note that it is not necessarily the case that imports and exports are schedulable on each of the specified interfaces.

of import-path FTRs, while export-path FTR holders are paid nothing. Analogously, in the event of export-path congestion, the ICP is paid to the holders of export-path FTRs, while import-path FTR holders are paid nothing. Thus, FTRs constitute a mechanism for the disposal of revenue collected by the ISO, the IESO in Ontario, as a result of congestion.

The total income earned by the holder of an FTR is the accumulation of hourly payments over the hours during which the FTR is valid. Mathematically, the payouts to import- and export-path FTRs, respectively, can be written as

$$Payout_{(Import) Path, Period} = \sum_{t=\underline{T}}^{\bar{T}} \min\{0, ICP_{Path, Period, t}\} \geq 0 \quad (V-1)$$

and

$$Payout_{(Export) Path, Period} = \sum_{t=\underline{T}}^{\bar{T}} \max\{0, ICP_{Path, Period, t}\} \geq 0 \quad (V-2)$$

where the period $[\underline{T}, \bar{T}]$ defines the range of hours over which the FTR is valid.

Given that the payout associated with an FTR is the accumulation of ICPs over a range of hours, and whereas ICPs measure the degree of congestion at an hourly level, it follows that FTR payout is a measure of aggregate congestion over the specified range of hours, either monthly or annual periods as the case may be.

FTRs are purely financial instruments and, therefore, do not provide physical access rights to the transmission system. Control over the allocation of capacity on the physical transmission system rests with the ISO.

2.2. Demand

The possibility of positive ICPs implies the possibility of positive FTR payouts. Holding FTRs in order to receive these payouts can be viewed as a mechanism for hedging the

uncertainty associated with congestion. This is the principal reason FTRs were created. Uncertainty regarding the magnitude of the ICP in any particular hour represents a potentially significant source of risk for inter-jurisdictional traders. Consider the example of a 1-unit (MW) export transaction on a particular path. Export congestion, as previously defined, results in the external zone price being greater than the uniform internal price by an amount equal to the absolute value of the ICP (see equation (V-2)). This represents an uncertain cost to exporters. However, since the ICP constitutes the income earned by the holder of one export-oriented FTR valid during the same hour, if the trader owned the FTR, the risk associated with congestion would be fully hedged. Essentially, the trader would pay the ICP to themselves. The price of this hedge, that is, the price of avoiding congestion uncertainty, is determined in the FTR auction market.

Participation in the FTR auction market is not limited to energy traders alone. Purely financial investors may also participate. For these agents, FTRs are simply financial assets in which they can invest. Irrespective of their purpose, agents must form expectations regarding the magnitude of the eventual payout.

2.3. Supply

In Ontario, as discussed in section 2.1, there are two durations of time during which an FTR is valid. A ST FTR is valid for all the hours of one particular calendar month. A LT FTR is valid for all the hours of four consecutive calendar quarters. The number of FTRs created by the ISO for each path is related to the physical transmission capacity anticipated to be available on that path.⁸⁶ This constitutes the supply of FTRs.

⁸⁶ The details of this process are complex and take account of, *inter alia*, planned transmission outages (internally and at various interties) and restrictions on the contemporaneous flow of power on different interfaces. Since these details are not relevant to the analysis conducted in this chapter, they are omitted.

2.4. Auction market

The ISO periodically conducts auctions in which it sells the FTRs it created. Analogous to their duration, auctions for ST and LT FTRs are conducted monthly and quarterly, respectively. There are, however, a number of structural differences between the two auction processes. The auctions for ST FTRs for month m , for all paths, are held mid-way through month $m-1$. Prospective FTR purchasers decide which auctions to bid in and submit their bids confidentially to the ISO. For each path, the ISO aggregates all bids to construct a demand schedule. Equilibrium, including the calculation of market clearing prices (MCPs), occurs in the standard manner. All bidders on a path pay the same MCP and each auction occurs in one round.⁸⁷

2.5. Benefits of financial transmission rights and associated markets

There are two significant sources of benefits related to FTRs. First, as discussed above, they provide a mechanism by which electricity traders can hedge the congestion risks associated with inter-jurisdictional trading. Second, the price (MCP) at which the market clears signals agents' expectations regarding congestion over the relevant period.

2.5.1. FTRs as hedging instruments

The availability of financial instruments to hedge congestion risk enhances the efficient functioning of the underlying electricity market. Without the ability to hedge congestion risk, traders who would have otherwise purchased FTRs would have to form expectations of transmission congestion over the relevant period of time and account for it in the bids/offers they make in the underlying electricity market. There is a significant

⁸⁷ Prior to October 2003 it was not always the case that ST FTRs for month m were auctioned in a single round mid-way through month $m-1$. Such FTR auctions were occasionally held prior to month $m-1$, and sometimes followed a two-round structure similar to that of LT FTR auctions.

possibility that the resulting power flows would be sub-optimal, that is, would not maximise total surplus subject to transmission constraints.⁸⁸

To see how holding an FTR impacts the risk associated with congestion uncertainty faced by traders, consider both a hypothetical exporter and a hypothetical importer of electricity from/to Ontario.

2.5.1.1. A hypothetical exporter

Suppose a trader arranges to export one MWh of electricity from Ontario to, say, Michigan in each hour h of month m . They would expect to pay the Michigan zonal price for each unit exported and to be paid a (Michigan) price by a consumer located in Michigan (perhaps at a contracted level).

The profit made by an exporter that does not simultaneously hold an FTR for the relevant transmission path is

$$\Pi_{\text{export}}^0_{ON_MI,m} = \sum_h \left[P_{MICHIGAN,m,h} - (HOEP_{m,h} + ICP_{ON_MI,m,h}) \right] \quad (V-3)$$

where

$P_{MICHIGAN,m,h}$ is the price received for the export from a customer in Michigan for hour h in month m ;

$HOEP_{m,h}$ is the hourly Ontario energy price (HOEP) for hour h ;

and

$ICP_{ON_MI,m,h}$ is the intertie congestion price (ICP) for the Ontario to Michigan transmission path for hour h in month m (as defined above).

⁸⁸ For theoretical discussion of the value of hedging in the context of commodity markets, see Bessembinder (1992) and Switzer and El-Khoury (2007).

From equations (V-1) and (V-2) it is known that

$$Payout_{ON_MI,m} = \sum_{\{h|ICP_{ON_MI,m,h} \geq 0\}} ICP_{ON_MI,m,h} \quad (V-4)$$

Define

$$R_{MI,m} = \sum_h P_{MICHIGAN,m,h} \quad (V-5)$$

and

$$C_{ON,m} = \sum_h HOEP_{m,h} \quad (V-6)$$

to be the revenue received for electricity from the customer in Michigan and cost paid for electricity in the Ontario wholesale market (excluding the impact of congestion), respectively, for all hours in month m . Using equations (V-4), (V-5), and (V-6), equation (V-3) can be rewritten as

$$\Pi_{\text{export}}^0_{ON_MI,m} = R_{MI,m} - (C_{ON,m} + Payout_{ON_MI,m}) \quad (V-7)$$

In words, the profit from exporting one MWh of electricity from Ontario to Michigan in each hour of month m without holding an FTR equals the revenue received from its sale less the sum of its wholesale market cost and (non-negative) congestion rents/payout. Since the payout term in equation (V-7) depends upon transmission system congestion that is uncertain at the time at which trades are physically scheduled, it represents, as described above, a financial risk faced by the hypothetical exporter that it may desire to hedge against.

To see how the purchase of an FTR impacts this risk, consider an alternative case where the hypothetical exporter holds an FTR. The profit made by an exporter that simultaneously holds an FTR for the relevant transmission path is

$$\Pi_{\text{export}}^1_{ON_MI,m} = \Pi_{\text{export}}^0_{ON_MI,m} - (MCP_{ON_MI,m} - Payout_{ON_MI,m}) \quad (V-8)$$

where

$MCP_{ON_MI,m}$ is the auction market clearing price for the FTR valid on the Ontario to Michigan transmission path in month m .

Substituting equation (V-7) into equation (V-8) yields

$$\Pi_{\text{export}}^1_{ON_MI,m} = R_{MI,m} - (C_{ON,m} + MCP_{ON_MI,m}) \quad (V-9)$$

In words, the profit from exporting one MWh of electricity from Ontario to Michigan in each hour of month m while holding an FTR equals the revenue received from its sale less the sum of its wholesale market cost and the price paid at auction for the FTR. These profits are independent of the transmission system congestion that is uncertain at the time at which trades are physically scheduled.

Thus, as comparison of equations (V-7) and (V-9) makes clear, holding an FTR hedges all of the exporter's risk associated with uncertain transmission system congestion.

2.5.1.2. A hypothetical importer

The situation of a hypothetical importer is largely analogous to that of an exporter, though the elements of the analysis are defined somewhat differently. Suppose a trader arranges to import one MWh of electricity from, say, Michigan to Ontario in each hour h of month m . They would expect to be paid the Michigan zonal price for each unit imported and to be pay a (Michigan) price to a producer located in Michigan (perhaps at a contracted level).

The profit made by an importer that does not simultaneously hold an FTR for the relevant transmission path is

$$\Pi_{\text{import}}^0_{MI_ON,m} = \sum_h \left[(HOEP_{m,h} - ICP_{MI_ON,m,h}) - P_{MICHIGAN,m,h} \right] \quad (V-10)$$

where

$ICP_{MI_ON,m,h}$ is the intertie congestion price (ICP) for the Michigan to Ontario transmission path for hour h in month m (as defined above)

and the other terms are defined as above.

Analogously to equations (V-4), (V-5), and (V-6),

$$Payout_{MI_ON,m} = \sum_h ICP_{MI_ON,m,h} \geq 0 \quad (V-11)$$

$$R_{ON,m} = \sum_h HOEP_{m,h} \quad (V-12)$$

and

$$C_{MI,m} = \sum_h P_{MICHIGAN,m,h} \quad (V-13)$$

which are aggregate transmission congestion on the Michigan to Ontario transmission path, the revenue received from the Ontario wholesale market (excluding the impact of congestion), and cost incurred for electricity in Michigan, respectively, for all hours in month m . Using equations (V-11), (V-12), and (V-13), equation (V-10) can be rewritten as

$$\Pi_{\text{import}}^0_{MI_ON,m} = (R_{ON,m} - Payout_{MI_ON,m}) - C_{MI,m} \quad (V-14)$$

In words, the profit from importing one MWh of electricity from Michigan to Ontario in each hour of month m without holding an FTR equals revenue received from its sale in Ontario, less the (non-negative) magnitude of transmission congestion, less the cost of the electricity in Michigan. Since the payout term in equation (V-14) depends upon transmission system congestion that is uncertain at the time at which trades are

physically scheduled, it represents, as described above, a financial risk faced by the hypothetical importer that it may desire to hedge against.

To see how the purchase of an FTR impacts this risk, consider an alternative case where the hypothetical importer holds an FTR. The profit made by an importer that simultaneously holds an FTR for the relevant transmission path is

$$\Pi_{\text{import}}^1_{MI_ON,m} = \Pi_{\text{import}}^0_{MI_ON,m} - (MCP_{MI_ON,m} - Payout_{MI_ON,m}). \quad (\text{V-15})$$

where

$MCP_{MI_ON,m}$ is the auction market clearing price for the FTR valid on the Michigan to Ontario transmission path in month m .

Substituting equation (V-14) into equation (V-15) yields

$$\Pi_{\text{import}}^1_{MI_ON,m} = (R_{ON,m} - MCP_{MI_ON,m}) - C_{MI,m} \quad (\text{V-16})$$

In words, the profit from importing one MWh of electricity from Michigan to Ontario in each hour of month m while holding an FTR equals the revenue received from its sale in Ontario, less the price paid at auction for the FTR, less the cost of electricity in Michigan. These profits are independent of the transmission system congestion that is uncertain at the time at which trades are physically scheduled.

Thus, as comparison of equations (V-14) and (V-16) makes clear, holding an FTR hedges all of the importer's risk associated with uncertain transmission system congestion.

2.5.2. Prediction of magnitude of congestion

The other benefit of the FTR market is the potential for forward prices to provide information regarding future congestion in the transmission system. In the context of FTR markets, an unbiased prediction is one that predicts the relevant average payout

and does not, therefore, systematically over- or under-estimate the degree of congestion. If forward prices constitute unbiased predictions of congestion, then traders can use this information to account for expected transmission when scheduling trades. As the uncertainty associated with trading would be reduced, this information supports the achievement of optimal power flow scheduling. Moreover, this information is especially beneficial to traders that did not purchase any FTRs, that is, those whose trading is unhedged (as they are not hedged against the cost of congestion).

As discussed in the introduction, assessing the unbiasedness of the forward market price at forecasting future congestion is the principal purpose of this chapter.

3. Theoretical characterisation of an informationally efficient forward market and econometric approaches to the assessment of forward market unbiasedness

In the long run, an informationally efficient forward market is one in which the expected return to speculation is zero, that is, prices reflect all available information. Assuming markets are competitive, transactions costs are zero, and economic agents are risk neutral, forward market efficiency implies that k -period-ahead forward prices observed in period t , $f_{t,k}$, are unbiased predictors of k -period-ahead spot prices, s_{t+k} . The integer k can be thought of as the forecast interval. Symbolically,

$$E[s_{t+k}|\Phi_t] = f_{t,k} \quad (\text{V-17})$$

where $E[\cdot | \Phi_t]$ is an expectation conditioned upon the period t information set. Under the stated assumptions, deviations from the relationship described by equation (V-17) would be eliminated by arbitrage. The k -period-ahead linear forecasting equation associated with equation (V-17) is

$$E[s_{t+k}|\Phi_t] = \alpha + \beta * f_{t,k} \quad (\text{V-18})$$

with corresponding regression equation

$$s_{t+k} = \alpha + \beta * f_{t,k} + \varepsilon_{t+k} \quad (\text{V-19})$$

which may be augmented to include relevant additional regressors. This is a levels regression that characterises the long-run relationship between forward and spot prices.⁸⁹

Testing the market for informational efficiency/forward price unbiasedness amounts to testing the null hypothesis

$$H_0: (\alpha, \beta) = (0, 1) \quad (\text{V-20})$$

against the general alternative. This hypothesis, which is referred to as the joint informational efficiency hypothesis, is standard in this type of analysis. A finding of informational efficiency/forward market unbiasedness generally depends on failing to reject it. A more nuanced set of hypotheses—that consider α and β separately as well as together—to test for informational efficiency/forward market unbiasedness are outlined in section 6. The purpose for hypothesising about each parameter separately is that equation (V-20) being rejected does not imply both conditions contained therein are to be individually rejected, that is, one may still hold, and that outcome may be informative in relation to understanding market performance.

⁸⁹ An alternative approach to the assessment of forward market efficiency widely analysed in the econometric literature is to consider the forward premium, $f_{t,k} - s_t$, as constituting an unbiased forecast of the k -period change in the spot price, $s_{t+k} - s_t$. See Fama (1984) for more information. Symbolically,

$$E[s_{t+k} - s_t | \Phi_t] = f_{t,k} - s_t$$

where the variables are defined as in the main text. The associated forecasting and regression equations are variants of equations (V-18) and (V-19). Hodgson, Linton, and Vorkink (2004) refer to this regression equation as a stationary *regression* that characterises the short-run dynamics of the underlying market. An extensive comparison of the levels and stationary *regression* approaches can be found in Barnhart and Szakmary (1991). The stationary *regression* approach is not implemented in this chapter.

Direct estimation of equations such as equation (V-19) with standard single-equation techniques such as OLS and Tobit can be made provided the forward and spot price time series are stationary. If the time series are not stationary, even with allowance for structural breaks, there may still exist a cointegrating relationship between forward and spot prices.

3.1. Censored dependent variable

The spot price, s , is the dependent variable in the above analysis. With respect to the analysis of forward market unbiasedness, the spot price is the payout to an FTR holder.⁹⁰ As described by equations (V-1) and (V-2) in section 2, the payout variable is non-negative by definition. In particular, the payout to an FTR is observed to be positive when there is positive congestion on the relevant direction, on the relevant path. Otherwise, the payout is observed to be zero—even if there is positive congestion in the other direction of the same path. Thus, the payout variable is left-censored at 0.⁹¹ As a result, the payout variable, s , can be interpreted as observable variable associated with the unobservable latent variable, s^* , where:

$$s_t = \begin{cases} s_t^* & \text{if } s_t^* \geq 0 \\ 0 & \text{if } s_t^* < 0 \end{cases} \quad (\text{IV-21})$$

One approach to proceeding with the estimation of equation (V-19) under such circumstances would be to implement the standard one-stage Tobit maximum likelihood procedure. See Amemiya (1984) for a thorough survey of Tobit models.

⁹⁰ In the context of this analysis, the terms spot price, dependent variable, and payout, as well as the symbol s , are synonymous with one another and refer to an aggregate value of congestion over a relevant period of time, which is itself synonymous with the sum of hourly intertie congestion prices (ICP) over the corresponding range of hours as defined by equations (V-1) and (V-2) in section 2.

⁹¹ Strictly speaking it is the ICP that is left-censored. Aggregates of ICP, as defined in equations (V-1) and (V-2), will also be censored at the same point.

Alternatively, a two-stage Heckman (1976, 1979) selection-type approach could be implemented. In the first stage, a binary censoring (versus no censoring) dependent variable would be modelled by use of a probit model with the intent of generating a regressor—the inverse Mills ratio (IMR)—to augment equation (V-19). In the second stage, the resulting augmented version of equation (V-19) would be consistently estimated by OLS even in the presence of censoring.

If a meaningful proportion of observations are censored in some way, OLS estimation of equation (V-19) would produce biased and inconsistent estimates. Use of techniques that account for censoring must, therefore, be conditional upon the incidence of censoring in the observed data. This is addressed in sections 5 and 6.

3.2. Path-by-path and seemingly unrelated regression approaches

As described in section 2, there are numerous distinct transmission paths connecting Ontario's electricity market with those of its neighbours. Equation (V-19) can be estimated with single-equation techniques for each path. However, recognising that forward markets for each path clear centrally⁹² and simultaneously, and that realised payouts for each are related to Ontario's physical electricity market and therefore to each other, it is reasonable to expect the disturbances associated with equation (V-19) for each path to be correlated. In comparison to the path-by-path application of single-equation techniques, application of Zellner's (1962) feasible GLS estimator for seemingly unrelated regressions (SUR) is anticipated to result in more efficient estimates and, therefore, more precise hypothesis test results.

Zellner's GLS-SUR estimator can be implemented to improve upon OLS whenever OLS itself is applicable. The method cannot be used to improve upon Tobit model estimates

⁹² As stated in section 2, all of these markets are centrally managed by the IESO in Ontario.

(as the dependent variable is censored), but it can be implemented in the second stage of Heckman's two stage alternative.

3.3. Panel data approach

Since the same basic observations regarding FTRs and related variables are made with respect to each transmission path, the data set—which is described extensively in section 5—is, in fact, a panel. Other than the use of the GLS-SUR estimator, the approaches described above entirely suppress this feature of the data by considering each path as a distinct, independent FTR market. However, the forecasting equation (V-18) and its associated regression equation (V-19) can be reinterpreted in a standard panel data model context in which fixed- and/or random-effects are permitted in linear and censored specifications. This construction of the data permits testing the pooling hypothesis in which path distinctions are assumed to be irrelevant under the null hypothesis.

4. Previous analyses of forward market unbiasedness

There exist many analyses of forward market unbiasedness. This section briefly reviews a selection of these. Those related to markets for financial transmission rights will be reviewed first and in relatively greater detail. Following this is a selection relating to other markets.

4.1. Unbiasedness and financial transmission rights

Despite the significant size of the underlying electricity market, Ontario's FTR market has not been studied extensively. Most analysis that has been conducted with respect to this market is contained in the semi-annual reports of the Ontario Energy Board's (OEB)

Market Surveillance Panel (MSP).⁹³ Of these reports, the most extensive analysis is contained in the August 2010 report (MSP, August 2010) and covers the time period June 2002 to March 2010. The descriptive and graphical analysis contained therein studied the various paths⁹⁴ collectively and individually by directly comparing MCPs to payouts. Regardless of the approach, the report concluded that while FTR market performance varied across the paths considered, the market as a whole was not informationally efficient in the sense that the MCP for a particular auction appeared to provide relatively little information regarding the associated payout. These results suggest that the FTR market provided neither a good signal of future congestion, nor a useful financial hedging instrument.

Outside of Ontario, the New York FTR market is by far the most extensively studied.⁹⁵ New York FTRs differ in a fundamental sense from those in Ontario: there is no non-negative payout restriction. Consider a simple example. Suppose there is a transmission line from point A to point B. In Ontario, as discussed in section 2, there exist distinct transmission rights for the paths from point A to point B and from point B to point A, respectively, and the payouts on each path are non-negative as described by equations (V-1) and (V-2). However, in New York there is no lower bound on the payout.⁹⁶ Thus, if the transmission line was congested in the direction from point A to point B, holders of the A to B FTR would receive a positive payment (as they would in Ontario) while holders of a B to A FTR would receive a negative payout, that is, they would have to pay a positive-valued congestion charge (unlike in Ontario where, as stated, the payout would be limited to zero). This characteristic constitutes a fundamental difference between the two markets. It is expected that FTR bidders

⁹³ Prior to the reforms of the *Electricity Restructuring Act, 2004*, the MSP was part of the IESO.

⁹⁴ A limited number of paths were excluded from the analysis due to a lack of observations.

⁹⁵ The underlying electricity market opened in New York in November 1999, with the FTR market opening at the beginning of 2000.

⁹⁶ Thus, equations (V-1) and (V-2) collapse into a single-equation representation of the payout.

account for the possibility of a negative payout when bidding and will have, in particular, to form expectations regarding the pattern of future congestion as well as its magnitude. Unless otherwise stated, the literature cited below is based upon analysis of the New York FTR market.

The earliest study of FTR market performance in New York was Siddiqui, Bartholomew, Marney, and Oren (2005), which focused its attention on the performance of six-month-duration FTRs sold at the first four auctions over the years 2000 to 2001.^{97, 98} Their study was not econometric in nature, but instead constituted a direct comparison of MCP to payouts. The authors conclude the FTR market generally predicts the average direction of congestion, that is, positive (negative) MCPs were found to be highly positively correlated with positive (negative) payouts. However, they also found that the magnitude of payouts generally exceeded the magnitude of MCPs, with the result that FTRs were systematically profitable for traders. These results suggest some degree of informational efficiency in the FTR market, namely, the prediction of the direction of future congestion. In drawing conclusions, it is important to reiterate that the data set analysed covered a small number of auctions held over a small period of time at the beginning of New York's FTR market.

Hadsell and Shawky (2009) analyse New York FTR data over the 24-month period May 2006 to April 2008. In particular, they seek to determine whether the MCP provides an unbiased estimate of future congestion by estimating the following equation with the standard OLS technique:

$$Payout_{d,y,i} = \beta_{d,y,0} + \beta_{d,y,1} * MCP_{d,y,i} + \varepsilon_{d,y,i} \quad (V-22)$$

⁹⁷ In New York, FTRs are known as transmission congestion contracts (TCC). This terminology is due to Hogan (1992).

⁹⁸ As implied in section II, FTRs of this duration are not available in Ontario.

where $d = 1, 2, 3$ represents the three FTR durations available in New York, $y = 2006$, 2007 represents the periods May 2006 to April 2007 and May 2007 to April 2008, respectively, and i indexes the auctions within each duration-group. The path-specific nature of the FTRs is ignored and, unlike in Siddiqui, et al. (2005), no distinction is drawn between FTRs characterised by positive or negative MCPs. Each of the six sets of results—the six combinations of d and y —are then separately tested to determine statistically whether (i) the intercept estimate equalled zero or not and (ii) the slope estimate equalled one or not.⁹⁹ The results indicated that for one-month FTRs the marginal effect diverges significantly from one, sometimes to the up-side and sometimes to the down-side. With respect to the six-month and one-year FTRs, the results indicated that there was a consistently positive and significant portion of the payout was not explained by the variation of MCPs. Taken together, the results suggest a lack of informational efficiency in the New York FTR market, though with respect to the six-month FTRs, not as large as was found by Siddiqui, et al. (2005) using data from six years earlier.¹⁰⁰

Adamson, Noe, and Parker (2010) undertakes a more complex econometric analysis of New York's FTR market over the 70-month period September 2000 to June 2006. They separate the data into four groups: by the sign of the MCP (variable s) and by whether the relevant transmission path is entirely within the New York City area or not (variable g).¹⁰¹ As a result of this grouping, they estimate four variations of both of the following models with OLS, implementing the Huber-White standard error correction:

⁹⁹ Results of testing for the intercept and slope coefficient estimates jointly being 0 and 1, respectively, are not reported.

¹⁰⁰ Given the differences of the approaches taken in their respective analyses, inferences such as this are of limited import.

¹⁰¹ The principal rationale for differentiating FTR data based on geographic characteristics is that since the transmission system in the vicinity of New York City is often heavily congested, that portion of the market may behave in fundamentally different ways as compared to elsewhere in the state.

$$Payout_{s,g,t} = \beta_{s,g,0} + \beta_{s,g,1} * MCP_{s,g,t} + \varepsilon_{s,g,t} \quad (V-23)$$

and

$$Payout_{s,g,t} = \beta_{s,g,0} + \frac{\beta_{s,g,01}}{1+t} + \beta_{s,g,1} * MCP_{s,g,t} + \frac{\beta_{s,g,11}}{1+t} * MCP_{s,g,t} + \varepsilon_{s,g,t} \quad (V-24)$$

where t indicates the month since the New York FTR market opened. They characterise equations (V-23) and (V-24) as base and dynamic models, respectively. The difference between the two models is that over time the term $(1 + t)$ increases such that the second and fourth terms of equation (V-24) tend to zero. The authors argue that the addition of these effects in equation (V-24) capture some element of the learning that occurs as time progresses, recalling that the FTR market in New York—as in Ontario—was created simultaneously with the underlying electricity market, meaning that there was very little practical experience with FTRs at the time the data set begins. The approach thereafter is to estimate the base and dynamic models in order to answer two questions. First, are the FTR markets informationally efficient? Second, is there evidence of learning over time? To that end, each of the eight sets of results was tested in relation to the following hypothesis test—which was characterised above as a joint informational efficiency hypothesis

$$H_0: \beta_0 = 0 \text{ and } \beta_1 = 1 \quad (V-25)$$

against the general alternative.

For each of the eight models, the results can be used directly to assess the informational efficiency issue. In comparing the base and dynamic models to assess the learning issue, the authors argue that if the F-statistic associated with the hypothesis test equation (V-25) is smaller for the dynamic model than for the base model this can be taken as evidence that there was learning in the FTR market over time.

The results suggest rejecting the null hypothesis of informational efficiency for all eight models. However, on the basis of the process described above, the results also suggest that learning is occurring over time in that, while MCPs may not provide unbiased estimates of future congestion, their performance has improved since market opening.

Other empirical analysis of the New York FTR market include Adamson and Englander (2005) and Hadsell and Shawky (2006).

As stated, in markets where transmission rights are purely financial, the allocation of scarce transmission capacity is co-optimised by the ISO with electricity dispatch. The alternative to this centralised approach is a decentralised approach in which the relevant physical transmission rights must be procured by traders themselves in order to enable their transactions to be scheduled. This is a fundamental distinction between financial and physical transmission rights. Analogously, markets with decentralised transmission capacity allocation do not have public, periodic centralised transmission right auctions. These transmission rights markets tend to be characterised by many bilateral agreements that are not as readily observable as the outcomes of centralised FTR auctions. Markets with physical transmission rights have been studied. However, due to the key differences discussed, the results of these studies are not directly relevant to Ontario and the analysis undertaken in this chapter. For example, see De Vany and Walls (1999) for a discussion of physical transmission rights markets in the western United States.

4.2. Unbiasedness and non-FTR markets

Notwithstanding the limited examination of the forward markets unbiasedness hypothesis with regard to FTR markets, it has been extensively analysed in the context of other markets, including foreign exchange, commodity, and shipping markets, using models and techniques discussed in the previous section and section 3.

With respect to foreign exchange markets, evidence in favour of the forward market unbiasedness hypothesis has been inconsistent. For instance, in the context of the levels regressions, Hodgson, Linton, and Vorkink (2004) report robust evidence in favour of the hypothesis irrespective of the currency pair under consideration, the particular estimator applied, the forward horizon considered, or the observational frequency. This general conclusion is decidedly not the case in the context of stationary regression specifications.¹⁰² In fact, Hodgson, et al. (2004) state “it is something of a stylized fact in the literature that slope estimates are generally found to be less than one, and, in many cases, significantly negative” (p. 347).

The hypothesis has also been examined in relation to various markets for raw materials, with inconclusive results here as well. Chowdhury (1991) rejects the hypothesis in relation to copper, lead, tin, and zinc. Moore and Cullen (1995) do not reject the hypothesis in relation to aluminum, copper, lead, and zinc. Watkins and McAleer (2004) provide an extensive review of research regarding the hypothesis with respect to non-ferrous metals.

Kavussanos, Visvikis, and Menachof (2004) test the hypothesis in the context of dry- and wet-bulk shipping markets by consideration of forward freight agreement prices in relation to spot-market shipping prices. They find that one- and two-month forward prices constitute unbiased predictors of spot market shipping prices for all shipping routes under consideration, while three-month forward prices constitute unbiased predictors for a sub-set of these paths. In sum, they conclude that the validity of the hypothesis is market specific.

¹⁰² See section 3 of this chapter.

5. Data for FTR analysis

This section describes the data used in the analysis of FTRs. Data regarding the relative importance of the two auction duration types—ST and LT, respectively—are presented in section 5.1. Particular measures of profits and returns are given in section 5.2. Data related to ST FTRs, which are observed at a monthly frequency, are then discussed in section 5.3. A comparable discussion of data related to LT FTRs, which are observed at a quarterly frequency, is reported in chapter VI. Section 5.4 briefly describes the relevant data sources.

5.1. Aggregate FTR profitability and the relative importance of FTR durations

As discussed above, FTRs in Ontario are available in two rights durations: one month (ST) and twelve months (LT). Auction revenues and payouts for the paths under consideration, by rights duration, are reported in Tables V-1 and V-2, respectively. Values are reported in millions of dollars unless otherwise noted.

It is important to note that while ST FTRs have been available since June 2002, the ST FTR dataset employed in this analysis begins in November 2003. The reason for this is related to the structure of ST FTR auctions, as described in both the next section as well as section 2. With respect to LT FTR data, the period from market opening onward, with the exception of the last three quarters of 2010 due to non-completion, was used in

*Table V-1: Aggregate FTR auction revenue for imports and exports, by duration
(millions of dollars unless noted)*

Duration	Import Paths	Export Paths	Total	Percent of Total
Short-term	17.4	35.1	52.5	23.7
Long-term	82.1	86.9	169.0	76.3
Total	99.5	122.0	221.5	100.0

*Table V-2: Aggregate FTR payouts for imports and exports, by duration
(millions of dollars unless noted)*

Duration	Import Paths	Export Paths	Total	Percent of Total
Short-term	20.6	47.2	67.8	15.8
Long-term	136.6	225.8	362.4	84.2
Total	157.2	273.0	430.2	100.0

the LT component of analysis presented in Tables V-1 and V-2. Taken together, the percentages associated with ST FTRs in Tables V-1 and V-2 may understate the relative importance of ST FTRs in Ontario's electricity market. The net effect, however, is expected to be small.

With this in mind, consideration of aggregate auction revenues and payouts remains meaningful. As reported in Tables V-1 and V-2, aggregate auction revenues and payouts for the FTRs under consideration were \$221.5 million and \$430.2 million, respectively, which yielded a net profit of \$208.7 million to FTR buyers collectively. This is equivalent to a 94.2% rate of return to participating in the FTR market. The risk-free interest rate averaged 2.2% over this period (Table V-D6, located in Appendix V-D).

For import-path FTRs alone, aggregate auction revenues and payouts were \$99.5 million and \$157.2 million, respectively, yielding a net profit of \$57.7 million, which is equivalent to a 58.0% rate of return to participating in the FTR market. For export-path FTRs alone, aggregate auction revenues and payouts were \$122.0 million and \$273.0 million, respectively, yielding a net profit of \$151.0 million, which is equivalent to a 123.8% rate of return to participating in the FTR market.

With respect to LT FTRs alone, aggregate auction revenues and payouts were \$169.0 million and \$362.4 million, respectively, yielding a net profit of \$193.4 million, which is

equivalent to a 114.4% rate of return. With respect to ST FTRs alone, aggregate auction revenues and payouts were \$52.5 million and \$67.8 million, respectively, yielding a net profit of \$15.3 million, which is equivalent to a 29.1% rate of return.

Even allowing for differing FTR validity durations, these results are not consistent with a finding of forward market unbiasedness as they mean that MCPs systematically under-forecast eventual payouts. Nor are they consistent with a finding of informational efficiency as they suggest that there exist systematic opportunities to earn profits.

LT FTRs account for approximately three-quarters of auction revenue and five-sixths of payouts, with ST FTRs accounting for the remainder. Auctions associated with export paths have generated approximately one-quarter more revenue and three-quarters more payouts than those associated with import paths. This is consistent with the typical observation that Ontario's physical electricity grid is generally more export congested than import congested.

Notwithstanding the commonalities between ST and LT FTRs, there exist fundamental differences in the characteristics of the data associated with each. Both durations will be discussed in turn: ST FTRs in this chapter; LT FTRs in the next.

5.2. Definitions

The *profit* associated with holding an FTR is defined to be equal to the payout it generates for its holder less the market clearing price the holder paid for it. No other costs, such as carrying costs, are considered.

The *rate of return*, $R_{p,t}$, to holding an FTR on path p in month t is, by definition, equal to the ratio of the payout less the market clearing price (profit) and the market clearing price. That is:

$$R_{p,t} = \frac{\text{Payout}_{p,t} - \text{MCP}_{p,t}}{\text{MCP}_{p,t}} \quad (\text{V-26})$$

Rates of return in this analysis are not expressed as percentages. For instance, a rate of return of 0.3 is equivalent to +30%. This is to conserve space—especially in figures—since there is a very wide range of realised values. By extension, regardless of the (always positive) market clearing price, an FTR that receives a payout of zero has a rate of return of -1. Such cases constitute the censored observations discussed in section 3.

An alternative measure of profitability is *cumulative return*, CR_p (Market Surveillance Panel, August 2010). Analogous to the *rate of return*, it is defined to be equal to the ratio of the sum of all payouts less auction revenues and auction revenues for each path.

That is:

$$\begin{aligned} CR_p &= \frac{\sum_t [(\text{Payout}_{p,t} - \text{MCP}_{p,t}) * Q_{p,t}]}{\sum_t [\text{MCP}_{p,t} * Q_{p,t}]} \\ &= \sum_t \left[\frac{(\text{Payout}_{p,t} - \text{MCP}_{p,t})}{\text{MCP}_{p,t}} * \frac{\text{MCP}_{p,t} * Q_{p,t}}{\sum_t [\text{MCP}_{p,t} * Q_{p,t}]} \right] \\ &= \sum_t [w_{p,t} * R_{p,t}] \end{aligned} \quad (\text{V-27})$$

where $w_{p,t} = \frac{\text{MCP}_{p,t} * Q_{p,t}}{\sum_t [\text{MCP}_{p,t} * Q_{p,t}]}$ are auction revenue-based weights which, across all auctions on a path, sum to unity and $Q_{p,t}$ is the number of FTRs sold at auction. For each path, cumulative return can be interpreted as the proportion by which aggregate payout to FTR holders exceeds total auction market revenue.

As shown in equation (V-27), CR_p can be written as the weighted average of $R_{p,t}$.

Therefore, the (equally weighted) average of observed $R_{p,t}$ on a path is equivalent to the special case of equation (V-27) where all the weights, $w_{p,t}$, are equal to $1/T$, where T is the relevant number of time periods. Another special case is if all observed rates of

return are equal to $\bar{R}$. In this case, $CR_p = \bar{R}$ (since the weights sum to unity).

As described in further detail in section 2.1 of chapter VI, LT FTRs are auctioned in two rounds, with one-quarter and three-quarters of the rights auctioned in the first and second rounds, respectively. The MCP used to determine rates of return with regard to LT FTRs is the weighted average of the two recorded MCPs:

$$MCP_{LT\ Auctions} = 0.25 * MCP_{LT\ Round\ 1} + 0.75 * MCP_{LT\ Round\ 2} \quad (V-28)$$

The rate of return and cumulative return concepts will be applied to both ST and LT FTR markets below.

5.3. Data for ST FTR analysis

This section describes the data used in the analysis of ST FTRs.

5.3.1. Limitations of ST FTR analysis due to auction process and missing data

The discussion begins by narrowing the focus of further analysis to the (a) period of time and (b) set of paths for which the amount of (ST) data is meaningful.

Analysis of ST FTR market performance focuses on the period November 2003 to December 2010, inclusive. This 86 month period corresponds to the period where single-round ST FTRs were auctioned the month immediately before they were valid.

There are distinct 17 transmission paths connecting Ontario with neighbouring jurisdictions. In particular, with respect to Ontario there are paths to and from New York, Michigan, Minnesota, and Manitoba, as well as 9 paths between Ontario and Quebec. A complete list of these paths, with their sources, sinks, and corresponding names, is provided in Appendix V-C.

Table V-3: ST FTR: Path-by-path summary of missing observations

Path	# of Present Observations (maximum = 86)	# of Missing Observations	Proportion Missing
MBSI to ONZN	84	2	0.023
† MISI to ONZN	74	12	0.140
MNSI to ONZN	21	65	0.756
† NYSI to ONZN	75	11	0.128
PQAT to ONZN	15	71	0.826
PQBE to ONZN	77	9	0.105
PQDA to ONZN	80	6	0.070
PQDZ to ONZN	42	44	0.511
PQPC to ONZN	61	25	0.291
PQXY to ONZN	6	80	0.930
ONZN to MBSI	49	37	0.430
† ONZN to MISI	74	12	0.140
ONZN to MNSI	33	53	0.616
† ONZN to NYSI	73	13	0.150
ONZN to PQAT	15	71	0.826
ONZN to PQDA	45	41	0.477
ONZN to PQHZ	43	43	0.500

Section 2 described the FTR auction process. For each path there are months for which no ST FTRs are available to be auctioned. In such an event, no MCP is observed for the particular path and the observation is said to be missing. Other data for the path are still observed, including congestion, which, being a physical characteristic of the transmission system, exists independently of FTRs themselves. A path-by-path summary of the extent of missing data is provided in Table V-3.

Of the complete set of paths listed in Table V-3, attention will be focused on the subset comprised of paths to and from MISI and NYSI. These paths are the only ones for which FTRs are available in both directions of the relevant transmission line, with no

more than 15% of observations missing.¹⁰³ These paths are identified in Table V-3 with a dagger (†) at the left-side of the path name column.

Months for which there were no auctions—and therefore no MCPs—are excluded from the analysis. Missing observations complicate the estimation of models containing lagged variables such as the one-period lag of the difference between payout and MCP. The reason is that in the month following a missing observation the one-period lag is itself missing. The result is that the number of observations available for estimation declines, potentially by a large amount. The number of observations used to estimate each model is reported with the results themselves as described below.

5.3.2. Rates of profitability of ST FTRs

A histogram of the rates of return to ST FTRs is provided in Figure V-1, where import paths are distinguished from export paths. The left-most vertical bar represents those FTRs which received a zero payout for their holders. Table V-4 reports statistics regarding rates of return.

The distributions of import and export rates of return are both highly right-skewed, with the majority observations being negative, *i.e.*, the auction market clearing price is less than the corresponding payout—approximately 79% and 69%, respectively. These proportions are greater than that observed in LT FTR data, as reported in the next section.

For each path under consideration, and therefore for imports collectively and exports collectively, the mean rates of return are positive while the median is negative. This is in keeping with the distributions as described and illustrated. There are a small number

¹⁰³ For instance, the PQBE to ONZN path is excluded because there is no ONZN to PQBE path even though only approximately 10% of observations are missing.

Figure V-1: Distribution of rates of return to ST FTRs, by imports/exports

of very high observed rates of return which distort the mean but not the median. For instance, the highest observed rate of return was associated with the FTR valid for the Ontario to Michigan path in March, 2004. The rate of return was 5832, that is, 583,200%. This outcome was due to the auction market clearing price and payout being \$0.01 and \$58.33, respectively. Thus, high rates of return do not necessarily correspond to large absolute dollar payouts. Other extremely high rates of return include 508 in January, 2008 on the Ontario to Michigan path, and 98 and 61 observed on the New York to Ontario path in January, 2008 and May, 2010, respectively. It is because of observations such as these that the mean rate of return of FTRs on the Ontario to Michigan path is 87.58—even though the median is -0.80 and 72% were negative.

Statistics regarding cumulative return are provided in Table V-5. In comparison to the

Table V-4: Average and median rates of return to ST FTRs

	Michigan			New York			All Paths		
	Mean	Median	% < 0	Mean	Median	% < 0	Mean	Median	% < 0
Imports	0.68	-0.85	0.716	2.74	-1.00	0.867	1.71	-1.00	0.792
Exports	87.58	-0.80	0.716	0.90	-0.50	0.658	44.53	-0.62	0.687

Table V-5: Cumulative return to ST FTRs

	Michigan	New York	All Paths
Imports	0.056	0.299	0.105
Exports	0.399	0.295	0.329

mean rate of return, cumulative return is significantly less sensitive to extreme observations. This is because, as described by equation (V-27), cumulative return is constructed as the revenue-weighted average of the underlying rates of return.¹⁰⁴ As a result, FTRs such as the one for the Ontario to Michigan path for March, 2004 would receive relatively small weight due to the extremely small market clearing price. In fact, while the mean rate of return on the Ontario to Michigan path is 87.58, the associated cumulative return is 0.40. While this path is the most extreme of the four under consideration, it highlights the short-comings of drawing inference on the basis of mean rates of return.

5.3.3. Basic relationship between MCP and payout

Summary statistics regarding the MCP and payout for the four paths under consideration—collectively and individually—are reported in Tables V-D1, V-D2, and

¹⁰⁴ Consider a simple, two-period numerical example. Suppose that 1 FTR was available and sold in each of the two auctions and that the associated market clearing prices were \$1 and \$10, respectively. Finally, suppose the payout to each FTR was \$10. The mean rate of return would be 4.5 [= (9 + 0) / 2], while the cumulative return would be 0.82 [= ((10 + 10) – (1 + 10)) / (1 + 10) = 9 / 11].

V-D3 in Appendix V-D. Table V-D4 reports summary statistics for realised FTR profits. Table V-D5 reports the correlation coefficient between the MCP and payout—collectively and individually—for four paths. A test for statistical significance is reported. Table V-D6 reports summary statistics for various additional variables.

Figure V-D1 provides various scatter plots of the MCP and payout for the paths under consideration, with MCP equals payout lines superimposed. Figure V-D2 illustrates the same data as four time series plots. These figures are reported in Appendix V-D as well.

In particular, the mean payout exceeds the mean MCP for each path and, by extension, for all paths collectively. Collectively and on a path-by-path basis, payout and MCP are right-skewed, with payout being more right-skewed relative to MCP on each path except the one from Ontario to Michigan.

Payout and MCP range from \$0 to \$11,211.82 and \$0.01 to \$5,780.88, respectively, while profit ranges from negative \$3,102.22—observed on the Ontario to Michigan path—to (positive) \$9,902.38—observed on the Ontario to New York path. As with payout and MCP, profit is also right-skewed. The highest priced FTR that generated a payout of zero had a MCP of \$1,022.00 and was valid for July, 2006 on the Michigan to Ontario path.

The (contemporaneous) correlation coefficient between the MCP and payout is approximately 0.45 across all paths and, with a p-value of 0.000, is statistically significant. At the path level, with the exception of the New York to Ontario path, the correlation coefficients are statistically significant at any level of significance greater than 0.21%. These results, along with inspection of the appropriate data plots in Figures V-D1 and V-D2, suggest the presence of a meaningful relationship between the MCP and payout on all paths jointly and, with the exception of the New York to Ontario path, the individual path level as well.

The definitions of the HDD and CDD variables reported in Table V-D6 are given in section 6.

Overall, this preliminary analysis suggests additional research regarding ST FTR market performance would be worthwhile.

5.3.4. Stationarity

It is apparent from Figure V-D2 that time series stationarity may be a significant concern in any analysis of ST FTRs. Presuming a stable relationship exists between payout and MCP, analysis of stationary will focus on the properties of the payout time series because there are no missing observations to complicate the analysis. A summary of missing observations, by path, is given in Table V-3 above.

Table V-6 reports results of the application of two unit root tests, one that allows for structural breaks and another that does not, to establish the stationarity properties of ST FTRs. A standard unit root test—here, a modified Dickey-Fuller unit root test (DFGLS)—is applied to each series with results reported in the third column.¹⁰⁵ The results, for all paths, suggest that ST FTR data are characterised by unit roots. If

Table V-6: ST FTR: Stationarity

Path	N	DFGLS	Zivot-Andrews		Result
		Tau-stat.	Min. t-stat.	Break point	
MISI to ONZN	86	-2.169	-8.608***	27	Stat. w break
NYSI to ONZN	86	-2.293	-10.246***	24	Stat. w break
ONZN to MISI	86	-2.079	-5.784***	53	Stat. w break
ONZN to NYSI	86	-2.792*	-6.610***	54	Stat. w break

Note: * p<0.1, ** p<0.05, *** p<0.01

¹⁰⁵ The test is modified in the sense that the time series is transformed by a generalized least-squares regression. The maximum number of lags, k , is determined by the Schwert criterion in which $k = \{12 * ((T + 1)/100)^{0.25}\} = 11$ for this time series. The optimal lag length is determined by the Ng-Perron sequential t-test.

structural breaks are permitted in unit root testing, such as with the procedure of Zivot and Andrews (1992), the results are reversed. The minimum t-statistics are reported in the fourth column, with the corresponding break-point recorded in the fifth column.

Thus, all four paths under consideration are characterised by stationary payout series if structural breaks are admitted.

5.3.5. Incidence of ST FTR censoring

As described in section 5, models that account for the impact of censoring are estimated and reported below. To that end, Table V-7 reports data on the incidence of censoring over the 86-month study period for the four paths under consideration. Months without ST FTR auctions are not considered as censored. With respect to Figure V-D1 and Figure V-D2, censored observations correspond to points plotted on the various horizontal axes.¹⁰⁶

Approximately 40% of all payout observations (related to the four paths under consideration only) are censored. At the path level, the payout on the New York to Ontario path is most significantly censored, with approximately three-in-four payouts

Table V-7: ST FTR: Incidence of censoring for paths under consideration

Path	Number of Auctions	Number of Payouts Censored	Proportion of Payouts Censored
All paths considered	296	119	0.402
MISI to ONZN	74	27	0.365
NYSI to ONZN	75	56	0.747
ONZN to MISI	74	29	0.392
ONZN to NYSI	73	7	0.096

¹⁰⁶ MCPs are strictly positive. For Figure V-1, the points plotted on the various horizontal axes—the censored observations—are exclusively from the payout time series.

being so. On the other hand, less than one-in-ten realisations of payout are censored on the counter-path from Ontario to New York.

5.4. Data sources

Data on MCPs and payouts are from the IESO. Natural gas prices are from the United States Energy Information Administration and are converted to Canadian currency. Interest and exchange rate data are from the Bank of Canada. The weather data used to construct HDD and CDD are from the United States National Climatic Data Center. Data regarding near-term weather expectations are not available. These may otherwise have been potentially useful in explaining the variation of payout.

6. Econometric models, hypotheses, and methodology

The analysis of the performance of Ontario's FTR market reported in this chapter is based upon both panel and path-specific formulations of the relationship between MCPs and payouts. The main performance issues at interest are (i) whether the FTR auction market is informationally efficient, that is, whether the MCP constitutes an unbiased forecast of transmission congestion, and (ii) whether there is evidence of auction market participants learning over time, that is, whether MCP as an unbiased estimate of transmission congestion improves over time. To assess these issues, the approach taken in Adamson et al. (2010) is expanded upon.

6.1. Model specification

As described in section 3, the forward market unbiasedness hypothesis can be assessed with (a) a panel data framework and (b) a path-by-path framework, with seemingly unrelated regressions corrections to path-by-path estimates of standard errors.

In the panel data framework, the applicable model takes the form:

$$Payout_{p,t} = \alpha + \nu_p + \beta * MCP_{p,t} + X_{p,t} * \gamma + \varepsilon_{p,t} \quad (V-29)$$

where p indexes the four paths (groups), ν_p is the group-specific effect, β is the (scalar) parameter associated with MCP, γ is a vector of parameters associated with additional regressors, including appropriate dummy variables to account for structural breaks. Four configurations of additional regressors—I through IV in Table V-8—are considered in the panel data framework.

In the path-by-path framework, where each path is (initially) considered on its own and the group-specific effects are captured by the group-specific intercepts, the applicable model takes the form:

$$Payout_{p,t} = \alpha_p + \beta_p * MCP_{p,t} + X_{p,t} * \gamma_p + \varepsilon_{p,t} \quad (V-30)$$

for each of the four paths under consideration, for which there will be a unique set of parameter estimates. Eight configurations of additional regressors—I through VIII in Table V-8—are considered in the path-by-path framework.

Table V-8: Composition of $X_{p,t} * \gamma$

Configuration	Additional Regressors
I	Basic: appropriately defined dummy variables for structural breaks
II	Basic with convergence terms
III	Basic with contemporaneous regressors
IV	Basic with contemporaneous regressors and convergence terms
V	Basic with one-period lag of profits
VI	Basic with one-period lag of profits and convergence terms
VII	Basic with contemporaneous regressors and one-period lag of profits
VIII	Basic with contemporaneous regressors, lag of profits, and convergence terms

In order to be clear about the precise meanings of the additional regressors listed in Table V-8, equation (V-29) with configuration VIII is written below in fully-expanded form. Configurations I through VII are nested within configuration VIII.

$$\begin{aligned}
Payout_{p,t} = & \beta_{p,0} + \beta_{p,01} * \frac{1}{t} + \beta_{p,1} * MCP_{p,t} + \beta_{p,11} * MCP_{p,t} * \frac{1}{t} \\
& + \beta_{p,2} * hdd_posdev_source_{p,t} + \beta_{p,3} * hdd_negdev_source_{p,t} \\
& + \beta_{p,4} * cdd_posdev_source_{p,t} + \beta_{p,5} * cdd_negdev_source_{p,t} \\
& + \beta_{p,6} * hdd_posdev_sink_{p,t} + \beta_{p,7} * hdd_negdev_sink_{p,t} \\
& + \beta_{p,8} * cdd_posdev_sink_{p,t} + \beta_{p,9} * cdd_negdev_sink_{p,t} \\
& + \beta_{p,10} * nat_gas_price_t + \beta_{p,11} * nat_gas_capacity_share_t \\
& + \beta_{p,12} * nat_gas_price_t * nat_gas_capacity_share_t \\
& + \beta_{p,13} * risk_free_interest_rate_t \\
& + \beta_{p,14} * \{Payout_{p,t-1} - MCP_{p,t-1}\} \\
& + \sum_{p=1}^{p=4} \gamma_p * Dummy_P_t + v_p + \varepsilon_{p,t}
\end{aligned} \tag{V-31}$$

where p and t indicate the path and month of each observation.¹⁰⁷

The convergence terms in the even numbered specifications are similar to those in Adamson, et al. (2010), and are the second and fourth terms of equation (V-31). The contemporaneous regressors in specifications III, IV, VII, and VIII, are the HDD, CDD, natural gas price, natural gas capacity share, and risk-free interest rates of equation (V-31), while the lag of profit term—associated with the coefficient $\beta_{p,14}$ of equation (V-31)—is included in specifications V through VIII. Finally, $Dummy_P_t$ are the dummy

¹⁰⁷ November 2003, the first month of the study, is indexed as $t = 0$. If the first month in the data set was indexed as $t = 0$, then the formulation of the denominator in the second and forth terms of equation (V-31) would be as in Adamson, at al. (2010), as reproduced in equations (V-23) and (V-24).

variables defined on the basis the structural breaks reported in Table V-6.¹⁰⁸

The rationale for the inclusion of each regressor, as well as a discussion of its anticipated marginal effect, follows in the next section. Afterward, the particular techniques implemented are inventoried.

6.2. Regressors and anticipated marginal effects

The variables MCP and payout were discussed in detail in sections 2 and 5 above.

6.2.1. Controlling for demand variation

Configurations III, IV, VII, and VIII, include eight variables that control for demand variation through time and across the source and sink jurisdictions. These variables are constructed as follows.

For a given location, the number of heating degree days (HDD) can be defined as

$$hdd_location_t = \sum_{d \in t} \max\{0, 18 - temp_location_d\} \quad (V-32)$$

where $temp_location_d$ is the average temperature at the given location on day d , $18 - temp_location_d$ is the number of degrees by which the average temperature was below 18, $\max\{\cdot\}$ is positive to the extent that average temperature is less than 18 degrees, and $d \in t$ indicates that the days included in the sum are the days in month t .¹⁰⁹ Thus, $hdd_location_t$ is a measure of the extent to which weather was cold in each month. An analogous measure—cooling degree days—can be specified to capture the extent to which weather was hot in each month. It is

¹⁰⁸ Each of the four group-specific dummy variables is defined to be 1 in the months after the break reported in Table V-6 for the particular group and 0 otherwise. By definition this means the dummy variable for path p is 0 for all observations associated with other paths.

¹⁰⁹ All temperatures are recorded in degrees Celsius.

$$cdd_location_t = \sum_{d \in t} \max\{0, temp_location_d - 18\} \quad (V-33)$$

These measures have been developed because demand for electricity arising due to weather is not a monotonic function of the temperature itself. For instance, *ceteris paribus*, an increase of average temperature on a relatively hot day will increase demand for electricity, largely due to increased space-cooling load, whereas an increase in average temperature on a relatively cold day will decrease demand for electricity, largely due to diminished space-heating load. The 18 degree threshold is an approximation of the temperature at which temperature-based demand is minimised. Due to the physical characteristics of demand, the marginal effects of temperature changes on the demand for electricity are not symmetric around 18 degrees. This is the reason separate HDD and CDD indices are specified.

From equation (V-32) the average of $hdd_location_t$ can be determined for each month, yielding twelve unique values. It is convenient to think of this variable as capturing the long-term month-specific average of $hdd_location_t$. Call the resulting variable $hdd_location_average_t$. The realisation of how $hdd_location_t$ deviates from $hdd_location_average_t$ can then be determined. Thus,

$$hdd_dev_location_t = hdd_location_t - hdd_location_average_t \quad (V-34)$$

Analogous to the asymmetry of temperature-based demand around 18 degrees, the impact of deviations from long-term average weather characteristics on congestion, and therefore payouts, is not likely to be symmetric. Consider an import path FTR. If demand within Ontario is relatively high, *ceteris paribus*, either import congestion is more likely or the degree of import congestion is increased. The average impact of such a situation is to increase the payout. On the other hand, if demand within Ontario is relatively low, *ceteris paribus*, either the degree of import congestion will be lessened — to a minimum of no congestion — or a state of no import congestion will continue. The

average impact of either outcome is to decrease the payout. However, since these two average impacts are likely to differ, potentially to a significant extent, distinct variables to capture positive and negative deviations are specified as follows. They are

$$hdd_posdev_location_t = \max\{0, hdd_dev_location_t\} \quad (V-35)$$

and

$$hdd_negdev_location_t = \min\{0, hdd_dev_location_t\} \quad (V-36)$$

Hence, $hdd_posdev_location_t$ will be positive if a month is colder than average in a manner resulting in greater demand for electricity, and zero otherwise. The variable $hdd_negdev_location_t$ will be negative if a month is warmer than average in a manner resulting in less demand for electricity, and zero otherwise. Analogous variables can be constructed with respect to CDD.

From the argument above, for an import path FTR $hdd_posdev_location_t$ and $cdd_posdev_location_t$ are anticipated to be positively correlated with payout as greater values of these variables suggest, *ceteris paribus*, greater Ontario demand and therefore greater import congestion. The variables $hdd_negdev_location_t$ and $cdd_negdev_location_t$ are anticipated to be positively correlated with payout as well—recall that these variables are non-positively valued—as lower values of these variables suggest less Ontario demand and therefore less average import congestion. The use of multiple deviation variables allows for asymmetric marginal effects.

An alternative method for handling the asymmetry associated with the positive and negative deviations discussed above would be to square the positive deviations. This approach may be more intuitively pleasing as it would make more explicit the idea that the lower limit on congestion, that is, no congestion, does not have an upper limit analog. This issue will be returned to when the empirical results are examined below.

The arguments above implicitly assume that bidders in the FTR market form weather expectations precisely equivalent to long-term averages, which may very well be different over longer time horizons. It is on the basis of these expectations that deviations from the average are argued to lead to unexpected congestion. If, however, alternative expectations of weather were formed by bidders, the interpretations of these deviations are less straight-forward as some of the deviation may be accounted for in the MCP. As noted in section 5, data regarding weather expectations is lacking. The analysis, therefore, relies on the assumption that bidders' weather expectations are simply the observed long-term averages.

6.2.2. Natural gas generation and prices

Electricity generated from the combustion of natural gas is a critical component of supply in both Ontario and neighbouring jurisdictions. Higher natural gas prices, *ceteris paribus*, indicate a contraction of supply in each jurisdiction. However, without some heterogeneity in the characteristics of supply the effect of a price change would be equivalent across jurisdictions and there would be no impact on power flows on the transmission system. In practice, the relative proportion of supply comprised of natural gas-fuelled generation varies across jurisdictions. This will result in changes to power flows—and potentially the pattern of congestion—due to changing natural gas prices.

Higher natural gas prices are, on average, anticipated to instigate net power flows towards jurisdictions with relatively low proportions of supply derived from natural gas-fuelled generators. This is because higher natural gas prices increase costs and prices by a relatively small fraction in the jurisdiction with relatively low proportion of supply derived from natural gas-fuelled generators. This characteristic of supply has changed significantly over time for Ontario. In particular, since market opening in 2002 there has been significant investment in natural gas-fuelled generators in Ontario,

which reduces the extent to which this characteristic differentiates Ontario from its neighbours. To account for this diminished affect, the natural gas price is weighted with a term that measures the ratio of Ontario-based natural gas generating capacity with the sum of Ontario-based natural gas and coal generating capacity. This ratio is called *nat_gas_capacity_share*, and, as described above, has increased substantially since market opening.

Given the discussion above, higher natural gas prices are anticipated to be positively (negatively) impact payout on export (import) paths to (from) Michigan, Minnesota, and New York, while negatively (positively) impacting payout on import (export) paths from (to) Quebec and Manitoba. Moreover, the interaction term is anticipated to positively impact payout on export paths while negatively impacting payout on import paths.

6.2.3. Other variables

Changes in the risk-free rate of return are controlled for. The direct impact of the risk-free interest rate on congestion itself is likely to be small and, in any event, non-systematic in nature. For a given expected payout, however, higher interest rates reduce the present value of the associated FTRs, some fraction of which may be captured by the interest rate term. To the extent that any such effect is statistically significant, the marginal effect on payout of higher interest rates is anticipated to be positive.

Finally, the addition of the term $(Payout_{p,t-1} - MCP_{p,t-1})$ differentiates the first four configurations from the last four configurations reported in Table V-8. This term represents the one-period lagged difference between payout and MCP for path p , which can be thought of as both (i) the forecast error for the previous month's FTR auction and (ii) the profit earned by FTR holders in the previous period. It may be the case that

learning takes the form of FTR market bidders adjusting their bids based upon the error/profit realised in the previous period. In the event such an effect is a statistically significant determinant of the variation of payout, it is anticipated that a positive previous-period error/profit would result in a higher MCP in the current period. Thus, the associated coefficient is anticipated to be negative.

6.3. Hypothesis testing

Three sets of hypotheses related to informational efficiency and learning are considered where permissible by the regressors chosen. They are summarised in the next section, with each subsequently discussed in detail.

6.3.1. Summary of hypotheses considered

The hypotheses considered in this chapter are summarised in Table V-9. The parameters referred to are consistent with equation (V-31).

Table V-9: Summary of tested hypotheses

Hypothesis	Description of Null/Alternative Hypotheses
A	Intercept equals 0 / otherwise
B	Slope coefficient associated with MCP equals 0 / otherwise
C	Slope coefficient associated with MCP equals 1 / otherwise
D	Null hypotheses from A and C jointly / otherwise
E	Constant intercept / convergence component
F	Constant slope associated with MCP / convergence component
G	Null hypotheses from E and F jointly / any convergence terms
J	One-period lag of profit equals 0 / otherwise

6.3.2. Informational efficiency/forward market unbiasedness hypothesis

Recalling that the key purpose of this chapter is to assess Ontario's FTR market for informational efficiency, each estimated model is subjected to the following hypothesis tests:

$$\text{A. } H_0: \beta_{p,0} = 0 \quad H_1: \text{otherwise} \quad (\text{V-37})$$

$$\text{B. } H_0: \beta_{p,1} = 0 \quad H_1: \text{otherwise} \quad (\text{V-38})$$

$$\text{C. } H_0: \beta_{p,1} = 1 \quad H_1: \text{otherwise} \quad (\text{V-39})$$

$$\text{D. } H_0: \beta_{p,0} = 0 \text{ and } \beta_{p,1} = 1 \quad H_1: \text{otherwise} \quad (\text{V-40})$$

The four stated hypotheses test whether (A) the intercept differs from zero, (B) the slope coefficient associated with the MCP differs from 0, (C) whether the slope coefficient associated with the MCP differs from 1, and (D) whether the intercept and slope coefficient associated with the MCP are jointly equal to 0 and 1, respectively.

Hypothesis D is equivalent to equation (V-20), the joint informational efficiency hypothesis discussed above. When dealing with system estimates, the hypotheses both at a path-by-path level and jointly across all paths are tested.

When deciding whether the market under consideration is informationally efficient, the standard null hypothesis to consider is hypothesis D. Under hypothesis D payout and MCP vary proportionally, with none of the payout explained by the constant term. Under the null, MCP constitutes an unbiased forecast of payout and the market is informationally efficient.

Hypotheses A and C are the two components of hypothesis D. In particular, hypothesis A tests whether the intercept differs statistically from 0 while hypothesis C tests whether the slope coefficient associated with the MCP differs from 1. The benefit of these two tests is that if hypothesis D, the joint informational efficiency hypothesis is

rejected, it may be possible to determine why. There is valuable information in knowing whether rejection, if that is the case, is due to the intercept or the slope. Rejection of any of these hypotheses is suggestive of some kind of informational inefficiency.

Hypothesis B, which tests whether the slope coefficient associated with the MCP differs from 0, is useful as a general test of meaningfulness, that is, if it cannot be rejected then it cannot even be claimed that the MCP is increasing in the payout. Conversely to the other hypotheses—A, C, and D—failure to reject hypothesis is B is suggestive of a lack of informational efficiency. Under such an outcome the MCP would possess no ability to forecast payout.

6.3.3. Learning hypothesis: convergence over time

Adamson et al. (2010) analysed models similar to equation (V-31) to determine whether the inclusion of terms that allow both the intercept and the coefficient on the MCP—the second and fourth terms of equation (V-31)—to contain components that are initially non-zero but converge to zero through time as information and experience accumulate are meaningful in the explanation of the variation of payout. The following joint hypotheses will be tested, where regressors permit:

$$\text{E. } H_0: \beta_{p,01} = 0 \quad H_1: \textit{otherwise} \quad (\text{V-41})$$

$$\text{F. } H_0: \beta_{p,11} = 0 \quad H_1: \textit{otherwise} \quad (\text{V-42})$$

$$\text{G. } H_0: \beta_{p,01} = 0 \text{ and } \beta_{p,11} = 0 \quad H_1: \textit{otherwise} \quad (\text{V-43})$$

The three stated hypotheses test whether (E) the intercept contains a component that is initially non-zero but systematically converges to zero, (F) the slope coefficient associated with the MCP contains a component that is initially non-zero but systematically converges to zero, and (G) whether such components are contained in

both the intercept and slope coefficient associated with the MCP. The null hypothesis in each case is that such components are not statistically significant.

6.3.4. Learning hypothesis: realised error adjustment

The distinguishing feature of configurations V through VIII of Table V-8 is the inclusion of the term $(Payout_{p,t-1} - MCP_{p,t-1})$. The interpretation of this term was discussed earlier in this section. If it is the case that market bidders' behaviour in the FTR auction market is systematically impacted by the one-period lag of the difference between payout and MCP, then this term would be statistically significant. This would indicate the presence of a systematic error adjustment process. Where appropriate, the following hypothesis will be tested:

$$J. \quad H_0: \beta_{p,14} = 0 \qquad H_1: otherwise \qquad (V-44)^{110}$$

6.4. Methodology

In each case, linear models, with certain corrections to standard errors, are implemented first. Then, recognising the importance of censoring with respect to ST FTR data, alternative models that explicitly account for this issue are implemented, again with certain corrections to standard errors.

Using ST FTR panel data, the analysis begins by estimating equation (V-29) with regressor configurations I through IV from Table V-8. Pooled OLS and pooled Tobit techniques are implemented first. It then proceeds to implement various fixed-effects estimators. The standard linear least squares dummy variables model is reported first, followed by two fixed-effects approaches that account for censored data: (i) a Tobit dummy variables model, which is the Tobit analog of LSDV, and (ii) Honoré's (1992)

¹¹⁰ There are no hypotheses corresponding to letters H and I.

trimmed least absolute deviations model. Two random-effects models are then implemented: the standard linear model first, followed by its Tobit equivalent.

Using ST FTR data on a group-by-group/path-by-path basis, equation (V-31) is estimated for each path under consideration with regressor configurations I through VIII from Table V-8. The OLS estimator is applied first, reporting results with both unadjusted and Newey-West standard errors. The path-specific regression equations are then considered as a system of seemingly unrelated regression, to which the standard GLS-SUR estimator is applied.

To account for censoring, the Tobit estimator is then applied on a path-by-path basis. Finally, to deal more carefully with the left-censoring issue, a two-stage alternative to the Tobit approach is implemented. The first stage implements a probit model in order to estimate the probability, on an observation-by-observation basis, of censoring. The instruments used are listed and described with the estimation results below. A standardised inverse Mills ratio is added to equation (V-30), which can then be estimated by OLS. The two-stage approach to handling the censoring issue will also be estimated for the system of paths using a multivariate probit estimator in the first stage and a seemingly unrelated regressions estimator in the second stage.

7. Econometric results and discussion

Econometric results and discussion associated with the approaches and specifications described above are presented in this section. First, all approaches reported are inventoried and provide information regarding the location of comprehensive results in the various appendices. Discussion of the results follows.

7.1. Summary of econometric approaches

Table V-10 summarises the estimation approaches implemented with panel data regarding ST FTRs. Table V-11 provides a comparable summary where models are

Table V-10: ST FTR: Summary of econometric approaches using panel data

Brief Description of Econometric Approach	Appendix	Tables
Pooled linear / pooled OLS	V-E	E1 – E2
Pooled censored / pooled Tobit	V-E	E3 – E4
Linear fixed-effects / LSDV	V-E	E5 – E6
Censored fixed-effects / Tobit DV	V-E	E7 – E8
Censored trimmed least absolute deviations fixed-effects	V-E	E9 – E10
Linear random-effects	V-E	E11 – E12
Censored random-effects	V-E	E13 – E14
Comparison of fixed- and random-effects	V-E	E15 – E16

Table V-11: ST FTR: Summary of econometric approaches with group-level data

Brief Description of Econometric Approach	Appendix	Tables
Linear, OLS, Michigan to Ontario path	V-F	F1 – F2
Linear, OLS, New York to Ontario path	V-F	F3 – F4
Linear, OLS, Ontario to Michigan path	V-F	F5 – F6
Linear, OLS, Ontario to New York path	V-F	F7 – F8
Linear, SUR (all paths)	V-F	F9 – F15
Censored, Tobit, Michigan to Ontario path	V-G	G1 – G2
Censored, Tobit, New York to Ontario path	V-G	G3 – G4
Censored, Tobit, Ontario to Michigan path	V-G	G5 – G6
Censored, Tobit, Ontario to New York path	V-G	G7 – G8
Censored, Tobit, joint hypothesis test results (all paths)	V-G	G9 – G10
Heckman first-stage, probit, all paths	V-H	H1 – H2
Heckman second-stage, Michigan to Ontario path	V-H	H3 – H4
Heckman second-stage, New York to Ontario path	V-H	H5 – H6
Heckman second-stage, Ontario to Michigan path	V-H	H7 – H8
Heckman second-stage, Ontario to New York path	V-H	H9 – H10
Heckman second-stage, SUR (all paths)	V-H	H11 – H17

considered on a path-specific basis. A brief description of each model is reported in the first column of each table, while the appendix and table(s) in which the associated results are recorded is reported in the second and third columns, respectively. The tables referenced include diagnostic test results, when reported in separate tables, as well as hypothesis test results and confidence intervals for the parameter associated with MCP.

7.2. Results and discussion of ST FTR with panel data

This section focuses on the estimation of the regression equation (V-29) with ST FTR panel data. Unless otherwise stated, statistical significance, in the discussion that follows, refers to a 95% level of confidence.

7.2.1. Pooled cross-section estimators

Pooled linear estimator

Tables V-E1 and V-E2 report results associated with the estimation of four simple, linear regression configurations with OLS using pooled cross-section panel data.

In each of the four cases, the estimate of the coefficient associated with the MCP, β , is approximately 0.6. As reported in relation to hypotheses B and C, the estimate is statistically different from both 0 and 1. All intercept estimates are positive, but significantly so only for configurations I and II. Huber-White robust standard errors are calculated. In each case, approximately 25% of the variation of payout is explained by the various sets of regressors and the models are all highly statistically significant.

However, given that, as reported in Table V-7, approximately 40% of ST FTR observations were left-censored, the OLS estimator is biased and inconsistent. While the pooled OLS results may form a useful baseline for later comparison, they cannot be

viewed as conclusively meaningful in and of themselves.

Pooled Tobit estimator

To account for censoring, the Tobit estimator can be applied to the pooled cross-section, the results of which are reported in Tables V-E3 and V-E4.

The point estimates of β range, for the four configurations, from 0.551 to 0.872. Using robust standard errors, it can be concluded that β is statistically greater than 0, thereby rejecting null hypothesis B, for each configuration, whereas for the first three configurations it cannot be concluded that β is statistically different from 1, thereby failing to reject null hypothesis C, though it can be for configuration IV. Hypothesis A cannot be rejected in any case: estimates of the constant vary widely, but never statistically differ from 0. Hypothesis D, the joint informational efficiency hypothesis¹¹¹, can be rejected only for configuration IV.

The four configurations are each statistically significant, as determined by the realised values of the F-statistic, which applies to the model with robust standard errors.¹¹² The McKelvey-Zavoina R-square measure ranges from 0.324 for configuration I to 0.381 for configuration IV.¹¹³ As well, an F-test regarding the joint significance of the structural break dummies is significant for each configuration.

The smallest value of each information criterion is associated with configuration IV, suggesting it may dominate the other three in performance terms. (Recall that

¹¹¹ The joint informational efficiency hypothesis, as stated above, is equivalent to equation (V-20).

¹¹² The chi-square-statistic applies to the model with unadjusted standard errors.

¹¹³ The McKelvey-Zavoina R-square measure was introduced by McKelvey and Zavoina (1975). Veall and Zimmerman (1994, p.487) describe it as a ratio for which the numerator is a measure of explained variation and the denominator is a measure of total variation. Veall and Zimmerman (1994) conducts a Monte Carlo simulation study that compares various pseudo R-square measures and concludes that the McKelvey-Zavoina R-square is the best available. It can be interpreted as a proxy of the proportion of the variability of the latent variable explained by the regressors.

hypotheses B, C, and D can be rejected with this configuration.) In this case, $\beta = 0.551$, and ranges, with 95% confidence, from 0.192 to 0.910. Here, none of the three convergence learning hypotheses can be rejected, implying that convergence, as explicitly modelled, does not meaningfully contribute to the explanation to the variation of payout.

While the results of this analysis provide evidence that the ST FTR market is not informationally efficient, the results are not unambiguous, especially given conflicting results regarding hypothesis D for configurations I, II, and III, in comparison to IV.

7.2.2. Fixed- and random-effects

Recognising the data themselves are generated from four separate, potentially very different, transmission paths, it may not be appropriate to pool all observed data into a single cross-section. To that end, a variety of fixed- and random-effects estimators are considered, beginning with fixed-effects.

Linear fixed-effects/LSDV estimator

The simplest fixed-effects estimator is LSDV and Tables V-E5 and V-E6 report results associated with its application.

The point estimates for the four configurations vary over a narrow range from 0.453 to 0.510. Three sets of standard errors are reported: unadjusted, robust panel, and robust LSDV. Using robust panel standard errors it is concluded that β is both greater than 0 and less than 1, thereby rejecting hypotheses B and C, for each configuration. All point estimates of the constant are positive, though statistically so only for the first two configurations. Given the presence of three group-specific dummy variables, the interpretation of the constant is not as straight-forward as above. Taken together, the joint efficiency hypothesis, hypothesis D, can be rejected for each path. Two F-tests, one

of the joint significance of the fixed-effects and one of the joint significance of the structural break dummy variables, are both rejected for each configuration.

While these results suggest there is potential value to the fixed-effects approach, concern is warranted since, as with the pooled OLS estimator, the LSDV estimator is biased and inconsistent such that its application is not meaningful in and of itself.

Tobit fixed-effects/Tobit DV estimator

Since the LSDV estimator is biased and inconsistent when applied to censored data, one potential alternative is to use an equivalent Tobit DV estimator. Use of this estimator amounts to the application of the Tobit estimator to a model that includes dummy variables for all but one group/path in a manner analogous to the LSDV estimator.

Tables V-E7 and V-E8 report results associated with the application of the Tobit DV estimator.

The point estimates of β for configurations I, II, III, and IV, are 0.593, 0.552, 0.483, and 0.422, respectively. Using robust standard errors it can be concluded that all estimators are statistically greater than 0 and less than 1, thereby rejecting hypotheses B and C in each case.

The F-statistic associated with each configuration is highly significant, as is the F-statistic that tests the joint significance of the break dummy variables. Moreover, the McKelvey-Zavoina R-square measure is approximately 0.4 in each case. While the two information criteria do not suggest a single configuration dominates the others, the commonality of results across configurations reduces the meaningfulness of this outcome.

For the two configurations, II and IV, that permit convergence learning to be formally

assessed, there is little evidence that convergence, as modelled, meaningfully contributes to explaining the variation of payout.

In comparison to the estimates of β generated by the pooled Tobit estimator, the estimates of β obtained here by the Tobit DV estimator are uniformly lower, in configurations I and III by a large margin. Given the key difference is the presence of fixed-effects dummy variables here, this suggests there is value associated with the use of group-specific effects as market behaviour varies across the four transmission paths.

Taken together, application of the Tobit DV estimator provides little evidence of informational efficiency in the ST FTR market, especially with respect to the magnitude of β , though β was found to be statistically greater than 0.

Panel fixed-effects Tobit estimator

An alternative to the Tobit DV estimator is the trimmed least absolute deviations censored fixed-effects estimator proposed by Honoré (1992). The results associated with the implementation of this technique are reported in Tables V-E9 and V-E10.

The point estimates of β for the four configurations are 0.699, 0.586, 0.639, and 0.500, respectively. With unadjusted standard errors it can be concluded each statistically differs from 0, while all are statistically less than 1 other than for configuration I. While the estimation procedure does not produce standard errors for the constant, each of the four point estimates of the constant are positive.

Chi-square-statistics for all four configurations are highly significant, but aside from the direct MCP variables themselves, only the convergence term for MCP in configuration IV is statistically significant. As a result, configuration IV provides some limited evidence in support of the convergence learning hypothesis through the rejection of hypotheses F and G. Nevertheless, the results from the use of Honoré's fixed-effects

estimator for censored data provide limited evidence of informational efficiency in the ST FTR market.

Linear random-effects estimator

An alternative to modelling the group-specific effect as a fixed effect is to model it as a random effect. Provided certain conditions are satisfied, namely that there is no correlation between the random effects and the regressors, then the random-effects has greater estimation efficiency as they have fewer parameters requiring estimation. The simplest random-effects estimator is the linear random-effects estimator. Results associated with its application are reported in Tables V-E11 and V-E12.

The Breusch-Pagan Lagrange multiplier test for random effects is reported in the Tables. The purpose of this test is to assess the variability of the random effects in the model. Under the null hypothesis the variance of the group-specific effects is 0, that is, there are no random effects. The alternative is general. The random effects are far from being statistically significant in any of the four configurations. As a result, the estimation results are degenerate and are the exact same as under linear pooled OLS.¹¹⁴ See the associated discussion above. As stated above in the discussion regarding that approach, the pooled OLS estimator is biased and inconsistent given the degree of censoring present in the ST FTR data set.

Censored random-effects estimator

Since the linear random-effects estimator is biased and inconsistent, one alternative is to estimate its censored-data-adapted equivalent. Results of its implementation are

¹¹⁴ Technically, degeneration occurs when the estimated value of the variance of the random effects is negative, which is implausible, and therefore the estimate is set equal to zero. With no variation of the random-effects term, the random-effects model reduces to the pooled OLS form. A similar outcome occurs with respect to the censored-data-consistent random-effects estimator, except that in the event it degenerated due to lack of variation of the random-effects term it reduces to the pooled Tobit form.

reported in Tables V-E13 and V-E14.

The censored-data-adapted random-effects estimator is degenerate when applied to configurations II and IV, the variants that include the two convergence terms. The reported results for these configurations are the same as returned by the pooled Tobit estimator.

The estimates of β for configurations I and III are 0.636 and 0.522, respectively. Both of these estimates are statistically greater than 0 and less than 1, thereby rejecting hypotheses B and C in each case. While both estimated constants are positive, neither differs statistically from 0, thereby failing to reject hypothesis A in each case. Still, the joint informational efficiency hypothesis, hypothesis D, can be rejected in each case.

Both models are highly statistically significant.¹¹⁵ The AIC is lower and the log likelihood higher for configuration III.

Regardless of which configuration of regressors dominates, results of the censored-data-adapted random-effects estimator provide little evidence in favour of the information efficiency hypothesis in relation to the market for ST FTRs.

7.2.3. Comparison of fixed- and random-effects approaches

While the fixed- and random-effects approaches yielded similar results in terms of their parameter estimates, particularly of β , and overall conclusions finding little evidence in support of the informational efficiency of ST FTR markets, it is not as yet clear which approach is generally better.

The key issue is whether the random effects/unobserved heterogeneity are/is

¹¹⁵ Recall that dummy variables for structural breaks are included in the base model configuration and, therefore, all variants. Thus, the joint test for overall statistical significance does not reduce to a t-test in the case of configuration I.

independent of the regressors or not. Under a null hypothesis of no correlation between the random effects and the regressors, both fixed-effects and random-effects estimators are consistent but the fixed-effects estimator is inefficient as there is a coefficient to be estimated for each group. Alternatively, if the random effects are correlated with the regressors then, while the fixed-effects estimator remains consistent, the random-effects estimator is not. Thus, under the null hypothesis random effects is preferred, while under the alternative fixed effects are preferred. The specification test developed by Hausman can be used to determine whether the random effects are independent of the regressors or not.

The intuition of the Hausman test is simple, and is useful if two different estimators cannot easily be analysed by formal application of the test procedure, as is the case with respect to the censored data variants of the fixed- and random-effects estimators. If fixed- and random-effects estimators are both consistent, then the difference between their coefficient estimates should be small, that is, the estimation results should be broadly similar. The further the difference is from zero the more likely the null hypothesis is to be incorrect as it is increasingly likely that the unobserved heterogeneity is wrongly attributed to the group-specific variables.

Linear fixed- and random-effects estimators

Results of the application of the Hausman test to the linear fixed- and random-effects estimation results are provided in Table V-E15. With the exception of configuration IV, the results suggest the random effects are not independent of the regressors and, therefore, that the fixed-effects estimator is preferred. The converse is true for configuration IV.

However, as repeatedly noted above, linear estimators are biased and consistent when applied to significantly censored data.

Censored-data-adapted fixed- and random-effects estimators

As noted above, formal application of the Hausman test is not feasible in the context of censored panel regression models. However, the intuition underlying the Hausman test, as described above, can be brought to bear in this situation.

Table V-E16 reports a comparison of β as estimated by three censored-data-adapted estimators, two fixed-effects estimators (Tobit DV and Honoré trimmed least absolute deviations) and one random-effects estimator. For each of the four configurations under consideration the random-effects estimates of β were within the 95% confidence intervals associated with each of the fixed-effects β estimates. The comparison of estimated coefficients can be made with respect to other variables, where broadly similar results are obtained.

These results, in relation to the intuition described above, suggest the sufficiency of random-effects estimators in this analysis. Notwithstanding this conclusion, the results obtained by the consistent, yet inefficient, fixed-effects estimators may still be useful when drawing conclusions regarding the informational efficiency of ST FTR markets.

7.2.4. Summary of results of panel data analysis of ST FTRs

Application of various panel data approaches to the analysis of informational efficiency with respect to the ST FTR market in Ontario yields remarkably little evidence in their favour.

Informational efficiency and forward market unbiasedness imply, under the assumptions and discussion in sections 3 and 4, the slope parameter associated with MCP, β , and the intercept parameter will be 1 and 0, respectively.

The general result of this analysis is that estimates of β are repeatedly found to be

between, though statistically different from, 0 and 1. This result is robust to four regressor configurations, with various standard error corrections, in both linear and censored-data-adapted frameworks. With respect to the constant, while it is largely estimated to be a positive value, it is rarely statistically significant. While this result is as expected under the informational efficiency and unbiasedness null hypothesis, the conclusiveness of the results are at least partially due to the generally large standard errors associated with the point estimates.

These results are consistent with the findings of the statistical analysis reported in section 5.

The implication of these results is that while higher MCPs predict higher payouts, that is, the direction of the predicted correlation is positive, payout tends to rise by a magnitude greater than MCP. Thus, MCP is a biased predictor of payout. While this information is not fundamentally misleading, it does not correspond to the outcomes expected to be associated with an informationally efficient market.

7.3. Results and discussion of ST FTRs with individual transmission path data

This section focuses on the estimation of equation (V-30) on a path-by-path basis. Confidence intervals of estimates of β are reported at a 90% level of confidence.¹¹⁶ This is because, as discussed below, estimated standard errors are relatively large in comparison to those associated with the estimation of equation (V-29) using panel data. The four transmission paths subjected to path-by-path analysis are the same as were included in the panel: Michigan to Ontario, New York to Ontario, Ontario to Michigan, and Ontario to New York.

¹¹⁶ A 95% level of confidence was used previously. A lower threshold for confidence is used in this context as a result of limited sample sizes resulting in relatively large standard errors.

First, estimation results associated with the linear formulation of equation (V-30) are briefly discussed. Second, two censored-data-adapted formulations are considered: one-stage Tobit and two-stage Heckman.

7.3.1. OLS estimator

As reported in Table V-7, approximately 40% of ST FTR observations are left-censored. Without correction, the OLS estimator is biased and inconsistent under these circumstances. Notwithstanding this, results associated with its application are reported for use as a benchmark.

Econometric results associated with the application of the OLS estimator to equation (V-30) are reported in Appendix V-F. Tables V-F1 and V-F2 present parameter estimates for each regressor configuration with unadjusted and Newey-West standard errors for the Michigan to Ontario transmission path, as well as diagnostic and hypothesis test results. Analogous results for the New York to Ontario path are recorded in Tables V-F3 and V-F4, while for the Ontario to Michigan path they are recorded in Tables V-F5 and V-F6, and for the Ontario to New York path they are recorded in tables Tables V-F7 and V-F8.

Table V-F9 presents SUR estimates of equation (V-30) when the four path-level equations are estimated jointly.¹¹⁷ Tables V-F10 through V-F13, report hypothesis test results for the Michigan to Ontario, New York to Ontario, Ontario to Michigan, and Ontario to New York paths, respectively, using the SUR results reported in Table V-F9.

¹¹⁷ SUR point estimates are usually equal to OLS point estimates, with standard errors being more efficiently estimated by SUR. This is not the case here. The reason is that for a particular month to be used with SUR there must be an observation for every path for that month. Thus, if data are missing for a single month on any path the month is not used for any path. As a result, data used for the various paths for SUR is a subset of all data available. The data used for OLS could have been restricted so the point estimates would be identical, but this would amount to the unnecessary elimination of data. The standard errors associated with those results are not reported here.

Table V-F14 reports hypothesis tests for all paths jointly. Path-by-path confidence intervals regarding β , with unadjusted, Newey-West, and SUR standard errors, are reported in Table V-F15.

Michigan to Ontario transmission path

For the Michigan to Ontario path, OLS-estimated β for the basic model—configuration I—is 1.273, with a 90% Newey-West confidence interval ranging from 0.881 to 1.664. The point estimates of β for the other seven configurations range from -0.907 to 1.110, two of which are statistically less than 1. Three of the seven configurations—III, V, and VII—are statistically positive. These are the configurations, along with I, that lack the convergence terms. Application of SUR yields point estimates that are lower and standard errors that are smaller, but the general results are similar. In the configurations not containing convergence terms it is not possible to reject hypothesis D, the hypothesis of informational efficiency, though it is noted that the large standard error estimates are partly responsible for this. In the other configurations, except II, the informational efficiency hypothesis can be rejected, though this is largely due to the relatively low estimates of β itself. In these cases it is found that the convergence terms are statistically significant. Moreover, there is some evidence that the one-period lag of profits is statistically significant in configurations V through VIII.

New York to Ontario transmission path

With respect to the New York to Ontario path, the OLS-estimated β for the basic model is -0.155. It cannot be concluded that β differs statistically from 0 using either Newey-West or SUR standard errors for any of the eight configurations. Using SUR, all the point estimates of the intercept—except II—are positive, but statistically so only for configuration I. Taken together, there is no meaningful evidence of informational efficiency on this path. Use of SUR results does not alter this conclusion. These results

correspond to the finding reported in Table V-D5 that the correlation between payout and MCP is close to zero.

Ontario to Michigan transmission path

With respect to the Ontario to Michigan path, the OLS-estimated β for the basic model is 0.491, with a 90% Newey-West confidence interval ranging from 0.404 to 0.577. The point estimates of β for the other seven configurations range from 0.301 to 1.000, all of which are statistically greater than 0 and all but two of which—IV and VIII—are statistically less than 1, thereby rejecting hypothesis B in each case and hypothesis C in all but two cases. The average of the eight estimated β is 0.615, while the average standard error is 0.133. The point estimates of the intercept are all positive and they are statistically significant for half the configurations (I, II, V, and VI). Corresponding to these findings, the joint informational efficiency hypothesis, hypothesis D, can be rejected for all configurations except IV and VIII. There is no evidence the one-period lag of profit is useful for explaining payout, but there is some evidence that convergence in the form modelled does occur, though it is not uniform.

Ontario to New York transmission path

For the Ontario to New York path, the OLS-estimated β for the basic model is 0.649, with a 90% Newey-West confidence interval ranging from 0.418 to 0.881. The point estimates of β for the other seven configurations range from 0.091 to 0.703, half of which are statistically greater than 0 (I, II, V, and VI) but all of which are statistically less than 1, thereby rejecting hypothesis B for half the cases and hypothesis C for all cases. The average of the eight estimated β is 0.345, while the average standard error is 0.178. The point estimates of the intercepts are all positive and they are statistically significant for configurations I, II, V, and VI. Relating to these findings, the joint informational efficiency hypothesis, hypothesis D, is rejected for all configurations. There is little

evidence that either the one-period lag of profit or the form of convergence modelled is contributes meaningfully to explaining the variation of payout.

Summary of results with OLS estimator

Given the biasedness and inconsistency of OLS applied to censored data, there is little basis on which to draw formal conclusions regarding the informational efficiency of the ST FTR market. Notwithstanding this, the two import paths generate results that are more robust to regressor configurations than the two export paths. This suggests that there should be concern about the potential for regressor endogeneity in later analysis that accounts for censored data.

7.3.2. Tobit estimator

The Tobit estimator can be used to estimate equation (V-30) consistently with censored data. Econometric results associated with its application are reported in appendix V-G. Tables V-G1 and V-G2 present estimates of the eight regressor configurations with unadjusted and Huber-White standard errors for the Michigan to Ontario transmission path, as well as hypothesis test results. Various measures of goodness-of-fit are also reported. Analogous results for the New York to Ontario path are recorded in Tables V-G3 and V-G4, while for the Ontario to Michigan path they are recorded in Tables V-G5 and V-G6, and for the Ontario to New York path they are recorded in Tables V-G7 and V-G8, respectively. Table V-G9 reports hypothesis test results for all paths jointly. Table V-G10 reports 90% confidence intervals regarding β for each of the four paths.

Michigan to Ontario transmission path

For the Michigan to Ontario path, Tobit-estimated β for the basic model—configuration I—is 1.924, with a 90% Huber-White confidence interval ranging from 1.123 to 2.724. The point estimates of β for the other seven configurations range from -0.705 to 1.661,

four of which are statistically greater than 0, thereby rejecting hypothesis B. In two configurations—I and VIII—it is concluded that β differs statistically from 1, thereby rejecting hypothesis C in both cases. Given the wide range of estimates, the explanation for this result is that estimated standard errors are large, averaging 0.499. The estimated intercept is negative for all eight configurations, significantly so for each case except VI. Taken together, the joint informational efficiency hypothesis, hypothesis D, is rejected for each configuration except VI and VII (nearly rejected for VII). The convergence terms are significant only in configuration VIII (hypotheses E, F, and G) while the one-period lag of profit is significant in configurations V and VI (hypothesis J).

Overall, the various configurations of regressors are jointly significant in each case. The McKelvey-Zavoina R-square statistic rises from 0.36 with configuration I to 0.75 with configuration VIII. AIC is lowest for configuration VIII while BIC is lowest for configuration V. As reported above, the joint informational efficiency hypothesis is rejected for each of these configurations.

New York to Ontario transmission path

For the New York to Ontario path, Tobit-estimated β for the basic model—configuration I—is 1.033, with a 90% Huber-White confidence interval ranging from -0.884 to 2.949. Estimated β differs from 0 and 1 in only one case each, respectively, cases II and III. The estimated intercept is statistically negative for configurations I, II, V, and VI—those lacking contemporaneous regressors. Otherwise, the point estimate is a large positive value that is occasionally significantly so.

While some configurations of the model explain very large proportions of the variation of payout, such as configuration III where the McKelvey-Zavoina R-square measure is 0.978, the MCP is not systematically important. The evidence suggests that payout, and

by definition congestion, on this path can be predicted by a combination of natural gas prices, the natural gas capacity ratio, and interest rates (which are, to some extent, acting as a proxy for the business cycle). These results, broadly speaking, suggest the absence of informational efficiency in the New York to Ontario FTR market in the sense that the MCP does not provide useful information towards predicting payout.

These results are consistent with those obtained from the statistical analysis reported above in section 5.3.

Ontario to Michigan transmission path

With respect to the Ontario to Michigan path, Tobit-estimated β for the basic model—configuration I—is 0.619, with a 90% Huber-White confidence interval ranging from 0.400 to 0.837. The point estimates of β for regressor configurations II through VII range from 0.347 to 0.838, while for configuration VIII the point estimate is 1.361. Estimated β differs from 0 (positively) in all but two cases—II and VI (hypothesis B). For configurations I, III, V, and VII—those lacking the lag of profit regressor— β is statistically bounded between 0 and 1 (hypotheses B and C). The estimated intercept differs from 0, thereby rejecting hypothesis A, only for configuration VII and is positive in this case. The joint informational efficiency hypothesis, hypothesis D, is rejected for the odd numbered configurations and not otherwise. The convergence terms are statistically significant for configurations II and VIII, while the lag of profit term is not significant for any configuration.

Each configuration of regressors is jointly statistically significant. The McKelvey-Zavoina R-square statistic ranges from 0.240 to 0.770 for configurations I through IV and from 0.161 to 0.628 for configurations V through VIII. AIC is lowest for case VI while BIC is lowest for case V. As stated above, rejection of the joint informational efficiency hypothesis occurs with configuration V but not VI.

Ontario to New York transmission path

With regard to the Ontario to New York path, Tobit-estimated β for the basic model—configuration I—is 0.710, with a 90% Huber-White confidence interval ranging from 0.351 to 1.068. For the other seven regressor configurations, point estimates of β range from 0.112 to 0.616. Aside from case I, estimated β differs from 0 only for cases II and V (hypothesis B), while it differs from 1 in all cases except I and II (hypothesis C). All point estimates of the intercept are positive, significantly so and thereby rejecting hypothesis A, only for cases V and VI. Taken together, the joint informational efficiency hypothesis is rejected for all configurations except I and II, the two configurations where β was found not to differ significantly from 1. The convergence and lag of profit terms are not statistically significant for any of the regressor configurations.

The relevant sets of regressors are jointly significant for each of the eight configurations, for which the McKelvey-Zavoina R-square statistic ranges from 0.133 to 0.466. AIC is lowest for configuration VII while BIC is lowest for configuration V. As stated above, the various informational efficiency hypotheses are rejected in relation to each of these configurations.

All transmission paths collectively

Considered across all paths, the joint informational efficiency hypothesis, hypothesis D, is rejected for each configuration of regressors. With few exceptions, estimates of β are found to differ from 1 while the intercept is found to differ from 0. Together, both convergence terms are found to be statistically significant, though not always individually. Evidence regarding the importance of the lag of profits is mixed.

Summary of results with Tobit estimator

Application, on a path-by-path basis, of the Tobit estimator to equation (V-30) yields

very little evidence of informational efficiency and forward market unbiasedness with respect to the ST FTR market.¹¹⁸ For the Ontario to Michigan and Ontario to New York paths—the two export paths—there is evidence of a systematically positive correlation between auction market clearing prices and realised payouts. However, as reported above, this is not a one-to-one relationship. In particular, the preponderance of evidence suggests that a \$1 increase of the MCP corresponds to a less than \$1 increase of payout, thereby suggesting that the MCP provides, on average, a biased forecast of payout.

With respect to the Michigan to Ontario path, estimates of β were found to be greater than those related to the two export paths, but, as noted, the standard errors associated with these estimates are also larger. Large standard errors suggest forecasts of payout are highly imprecise. As a result, while the estimate of β was quite different from 1 for the regressor configuration preferred by the AIC (configuration V), the difference was not statistically significant. Notwithstanding this, the preponderance of evidence suggests the FTR market lacks informational efficiency for this path as well. This is at least partially related to the estimated intercept being significantly negative.

With regard to the New York to Ontario path, there is evidence that payout can be predicted with some accuracy. However, the ST FTR market seems to contribute little to that end as there is little evidence of a systematic relationship between the MCP and payout.

Considering all paths together, path-by-path application of the Tobit estimator yields little evidence of systematic informational efficiency and forward market price

¹¹⁸ At a higher level of confidence, say 95%, the various confidence intervals would be larger in magnitude and it would, as a consequence, become more difficult to reject the various hypotheses, including that anything differed from 0. Notwithstanding the ability to conclude that β differs from 1, if it does not differ from 0 then any findings of informational efficiency would be suspect. Again, this points to the large magnitude of the standard errors.

unbiasedness. Instead, the results provide some evidence of risk aversion on the part of ST FTR market participants.

7.3.3. Two-stage Heckman estimator

A two-stage Heckman (1976, 1979) estimator can be used to estimate equation (V-30) consistently in the presence of censored data on a path-by-path basis as an alternative to the Tobit estimator. With this approach, the probability of an observation being censored is considered in the first stage, one result of which—the inverse Mills ratio (IMR)—is used in the second stage. By modelling the probability of censoring directly, rather than assuming all censored observations are equivalent, the possibility exists that the performance of the Tobit estimator can be improved upon.

First stage

Econometric results associated with the estimation, on a path-by-path basis, of the first-stage probit model are reported in Table V-H1 in Appendix V-H. Table V-H2 presents a simple check of the consistency of these results by summarising the proportion of observations censored and predicted to be censored for each path.

The instruments used to identify the first stage for the four paths are the global adjustment rate, the aggregate global adjustment, the 3-hour pre-dispatch to hourly Ontario energy price (HOEP) differential, and the HDD positive deviation for Detroit, respectively.¹¹⁹ The instruments are of differing quality. The best instruments available

¹¹⁹ The global adjustment, referred to in-text occasionally as the aggregate global adjustment, is the difference between the total payments made to certain generators and other market participants, and the market revenues they receive. It is typically measured in dollars and is determined at a monthly frequency. The global adjustment rate is defined as aggregate global adjustment divided by total Ontario—excluding export—demand. As demand is measured in MWh, the global adjustment rate is measured in dollars per MWh. This is also a monthly calculation. The GA was discussed in much greater detail in chapters II, III, and IV.

with regard to the Michigan to Ontario, New York to Ontario, and Ontario to Michigan transmission paths are statistically significant in their own right, as is the probit model overall. The McKelvey-Zavoina R-square statistic ranges from 0.27 to 0.39. However, the best instrument available with regard to the Ontario to New York transmission path is only statistically significant at a 93% level of confidence, leading to a McKelvey-Zavoina R-square statistic of only 0.11.

The check for consistency in Table V-H2 reports that the proportion of observations predicted by the relevant probit model to be censored differs by less than 1% from the proportion observed to be so for each path.

The probit model is used to calculate the IMR. This ratio, which may differ for each observation, is used in the second-stage to account for the probability that any individual observation may be censored.

Second-stage

Each regressor configuration estimated above with the OLS estimator will be augmented with the relevant IMR determined in the first-stage and then estimated again with OLS. Econometric results of this process are reported in Appendix V-H. Tables V-H3 and V-H4 present second-stage estimates of the eight configurations listed in Table V-8 augmented with the IMR—a generated regressor—from the first-stage with

The HOEP is the hourly electricity price charged to consumers (though it is not the only fee they pay). While the market clears in real time, the planning for real time that takes place beforehand includes the calculation of market clearing prices which may be interpreted as forecasts of real-time prices. This planning process occurs over a certain number of hourly intervals in advance of real time. The price that clears the hourly interval three hours in advance of real time is called the 3-hour pre-dispatch price. The differential between the 3-hour pre-dispatch price and the HOEP can, therefore, be thought of as the 3-hour HOEP forecast error and is observed for every hour. (Note: this is not the same as the difference between HOEP in one hour and HOEP three hours earlier.) The instrument used is the monthly mean of these deviations.

The HDD positive deviation for Detroit was defined in (26). The instrument is the monthly mean.

both OLS and Newey-West heteroskedasticity and autocorrelation consistent standard errors for the Michigan to Ontario transmission path. Diagnostic and hypothesis test results corresponding to the eight regressor configurations are also reported.

Analogous results for the New York to Ontario path are recorded in Tables V-H5 and V-H6, while for the Ontario to Michigan path they are recorded in Tables V-H7 and V-H8, and for the Ontario to New York path they are recorded in Tables V-H9 and V-H10.

Table V-H11 presents SUR estimates of the four paths estimated jointly for the eight specifications augmented with the appropriate IMR term. Hypothesis test results for the four transmission paths using the SUR results are reported in Tables V-H12 through V-H15. Table V-H16 reports hypothesis test results for all paths jointly and Table V-H17 reports path-by-path confidence intervals regarding β , with unadjusted, Newey-West, and SUR standard errors, respectively.

Michigan to Ontario transmission path

For the Michigan to Ontario path the second-stage estimate of β for the basic model—configuration I—is 0.694, with a 90% Newey-West confidence interval ranging from -0.033 to 1.421. The point estimates for β for the other seven configurations range from -1.275 to 0.597, six of which do not differ statistically from 0 while the seventh is statistically negative, thereby generally failing to reject hypothesis B. Four of the eight configurations produce estimates of β that do not differ from 1, in which case hypothesis C is not rejected. In each of these cases, estimates of β also do not differ from 0 either. It is noteworthy that the average magnitude of the standard errors is 0.469. All eight estimated intercepts are negative, six statistically so. Taken together, the joint informational efficiency hypothesis, hypothesis D, is rejected for configurations other than I, V, and VII. The convergence terms and the one-period lag of profits are generally significant, thereby rejecting hypotheses E, F, G, and J.

Overall, the various configurations of regressors are jointly significant in each case. While, as described above, the MCP is generally not statistically significant, various other regressors are. As a result, the R-square and adjusted R-square statistics range from 0.353 to 0.767 and 0.335 to 0.685, respectively, for the eight configurations with adjusted R-square being largest for case VIII. AIC and BIC are lowest for configurations VIII and VI, respectively. As reported above, the joint informational efficiency hypothesis is rejected for each of these configurations. These results, principally the lack of coefficient stability under different regressor configurations, are a classic symptom of endogeneity. Taken together, these results suggest a lack of informational efficiency in the Michigan to Ontario ST FTR market.

The SUR point estimates of β are similar to those obtained by the OLS estimator.¹²⁰ The purpose of using the SUR estimator as an alternative is to take advantage of correlations across paths so as to improve estimation efficiency and obtain smaller standard errors. The benefit is obtained here as the average standard error under SUR is only 0.342, a 27% reduction in magnitude as compared to OLS. Of the four positive estimates of β , one is statistically greater than 0 and less than 1 while the other three are statistically different from neither 0 nor 1. Thus, while the reduced standard errors allow somewhat stronger conclusions to be obtained, conclusions are generally unchanged. All eight intercept estimates remain negative, five statistically so. Results from consideration of the joint informational hypothesis, the impact of convergence terms, and the one-period lag of profit are also unchanged.

New York to Ontario transmission path

With respect to the New York to Ontario transmission path, regressors are jointly statistically significant only for configurations II and IV. Results associated with other

¹²⁰ The relevant issue is missing data.

configurations are henceforth ignored for this path. The second-stage estimates of β for configurations II and IV are -0.726 and -0.043, with 90% Newey-West confidence intervals ranging from -1.927 to 0.475 and -0.854 to 0.768, respectively. Therefore, neither estimate of β differs from 0 or is equal to 1, thereby failing to reject hypothesis B while rejecting hypothesis C. In addition, neither intercept estimate statistically differs from 0. Notwithstanding this, the joint informational hypothesis, hypothesis D, is rejected for both configurations. Finally, the convergence terms are significant in both configurations.

Application of the SUR estimator does not appreciably change the results described above, except that the estimated intercept related to configuration II becomes statistically negative. Regardless of the relative performance of the two configurations—in terms of R-square, adjusted R-square, AIC, and BIC—there is little evidence to support a finding of informational efficiency on the New York to Ontario ST FTR market.

Ontario to Michigan transmission path

For the Ontario to Michigan transmission path the second-stage estimate of β for the basic model—configuration I—is 0.476, with a 90% Newey-West confidence interval ranging from 0.383 to 0.568. The point estimates of β for the other seven regressor configurations range from 0.294 to 0.739, all of which are statistically greater than 0, thereby rejecting hypothesis B, and all but one of which are statistically less than 1 (configuration VIII), thereby generally rejecting hypothesis C. All intercept estimates are positive, though none are statistically significant, resulting in a failure to reject hypothesis A for any configuration. As a result, the joint informational efficiency hypothesis is rejected for each configuration other than VI and VIII. The one-period lag of profit is never significant and the results with respect to the convergence terms are

mixed.

Overall, each of the configurations of regressors is jointly statistically significant. The R-square statistic ranges from 0.165 to 0.406 while the adjusted R-square statistic ranges from 0.116 to 0.253. Both AIC and BIC are minimised with configuration V, where the estimate of β was 0.487, with a 90% Newey-West confidence interval ranging from 0.296 to 0.607, and the estimated intercept was insignificantly positive. While the MCP arrears to provide a biased forecast of the payout and the FTR market appears to be generally informationally inefficient, the intercept not differing from zero provides some evidence of informational efficiency nonetheless.

Application of the SUR estimator alters the above conclusions to some extent. Instead of all estimates of β being found to be positive and statistically significant, here it is found that only six of the estimates are positive, four of them statistically so. Moreover, while previously all but one estimate was not statistically less than 1, two are found here. All estimates of the intercept remain positive, but four of them—those corresponding to the configurations containing the set of contemporaneous regressors—are statistically significant. The joint informational efficiency hypothesis is rejected for the four configurations containing contemporaneous regressors and not otherwise. This suggests the previously identified evidence of informational efficiency is not robust.

Ontario to New York transmission path

With regard to the Ontario to New York transmission path the second-stage estimate of β for the basic model—configuration I—is 0.643, with a 90% confidence interval ranging from 0.407 to 0.879. The point estimates of β for the other seven configurations range from 0.049 to 0.708, three of which are statistically greater than zero. Therefore, hypothesis B is rejected for half—those configurations without the contemporaneous

regressors—of the eight configurations. All point estimates are less than 1, thereby rejecting hypothesis C in each case. While none of the eight estimated intercepts differ statistically from zero, thereby failing to reject hypothesis A in any case, six of them are positive. As a result, the joint informational efficiency hypothesis, hypothesis D, is rejected for each of the regressor configurations other than II. The one-period lag of profit is never statistically significant and the convergence terms are generally not either.

The relevant sets of regressors are jointly significant for each of the eight configurations. The R-square statistic range from 0.133 to 0.467, while the adjusted R-square statistic ranges from 0.073 to 0.292, and AIC and BIC are minimised with configurations VII and V, respectively. As stated above, the joint informational hypothesis was rejected in each of these cases.

Application of the SUR estimator somewhat reduces the strength of the OLS/Newey-West results. While the eight estimates of β are essentially unchanged, the standard errors associated with β are relatively larger in magnitude. Therefore, instead of half the estimates of β being statistically greater than 0, only two—the two configurations without contemporaneous regressors that are also without the lag of profit term—remain as such. Also, instead of all estimates being statistically less than 1, only six remain as such, with the two others being the configurations without contemporaneous regressors or the lag of profit term. The signs and statistical significance of the eight intercept estimates is unchanged. Taken together, instead of rejecting the informational efficiency hypothesis, hypothesis D, for all configurations except II, it can no longer be rejected for configurations I and VI as well. The convergence terms remain statistically insignificant, as does the lag of profit in the configurations with contemporaneous regressors.

All transmission paths collectively

For each of the eight configurations it is concluded that β is less than 1, though it differs from 0 in only three of the eight cases. The joint informational efficiency hypothesis, hypothesis D, is rejected in all cases. The intercept term differs from 0 for five of the eight regressor configurations. Moreover, the convergence terms are always statistically significant, while the lag of profit term is statistically significant in the configurations lacking the set of contemporaneous regressors.

For each of the eight configurations, it is concluded that β differs from 1, though it differs from 0 in only three of these cases. The joint informational efficiency hypothesis, hypothesis D, is rejected in all cases. The intercept differs from 0 for five of the eight configurations. Moreover, the convergence terms are always statistically significant, while the lag of profit term is statistically significant only in the configurations lacking the set of contemporaneous regressors.

Of all the configurations, VIII is preferred by AIC. Of the configurations without the one-period lag of profit term, IV is preferred by AIC. Assuming that configuration IV can be consistently estimated, the Hausman test suggests that endogeneity may be induced by the addition of the one-period lag of profit term. While instrumenting for this variable may be ideal, quality instruments are difficult to find. Instead, focusing of the results associated with configuration IV suggests it be concluded that β is less than 1 and not different from 0, while the intercept does differ from 0. Overall, these results, as reported above, suggest the rejection of joint informational efficiency hypothesis, hypothesis D, when the hypothesis is considered in relation to all paths simultaneously. Moreover, these results suggest the MCP provides a biased forecast of payout.

The result that path-level estimates of β vary widely in comparison to those from the panel data analysis suggests that some proportion of the path-level endogeneity

problem is controlled for by the panel data approach.

8. Conclusions

This chapter reports the results of a statistical and econometric analysis of the informational efficiency and forward market unbiasedness characteristics of Ontario's short-term (ST) financial transmission rights (FTRs) auction market. FTRs are financial assets that entitle their holder to receive payments proportional to the degree of congestion realised on the relevant transmission path (including the relevant direction). FTRs exist for all transmission paths connecting Ontario with its five neighbouring jurisdictions—New York, Michigan, Minnesota, Manitoba, and Quebec—and are individually valid for one of two durations—one month or one year.

8.1. Summary of results

It was determined that aggregate auction market revenues and payouts for all FTRs under consideration were \$221.5 million and \$430.2 million, respectively, yielding a profit of \$208.7 million—a 94.2% rate of return—to those economic agents who participated in the FTR market. Rates of returns of 58.0%, 123.8%, 114.4%, and 29.1% were found in relation to import-path only, export-path only, LT FTRs only, and ST FTRs only, respectively.

The principal issue related to ST FTRs is the left-censoring of payout at \$0, while the principal issue related to LT FTRs is the overlapping nature of the basic data set. Both issues are dealt with explicitly: ST FTRs in this chapter, LT FTRs in the next.

Analysis of the ST FTR market involved narrowing the focus to the four transmission paths connecting Ontario to and from New York and Michigan. The correlation coefficient between the MCP and payout suggested there is no systematic relationship between the two for the New York to Ontario transmission path, a result confirmed by

both formal econometric analysis and observation of the appropriate scatter plots. Significantly positive correlations were found in relation to the other three paths, for which formal econometric analysis confirmed a positive relationship between the MCP and payout, though not generally in a one-to-one fashion. As a result, it was concluded that the standard joint informational efficiency hypothesis should be rejected. Similar results were obtained by use of various estimators in a panel data context.

Regardless of the approach, it is concluded that while FTR market performance varied across the transmission paths considered and that some performed better than others, the market as a whole was not informationally efficient in the sense that the MCP for a particular auction does not tend to provide an unbiased forecast of future payout/congestion.

8.2. Future research

A brief discussion of possible areas of future research is provided in the concluding section of chapter VI, following its analysis of Ontario's market for LT FTRs.

Chapter VI: The market for long-term financial transmission rights

1. Introduction

Chapter V provided a general introduction to financial transmission rights (FTR) and their associated markets. The chapter also reported a statistical and econometric analysis of the informational efficiency and forward market unbiasedness characteristics of short-term (ST) FTRs in Ontario. This chapter reports an analysis of long-term (LT) FTRs in Ontario and can be interpreted as an extension of chapter V.

The motivation for analysis of the LT FTR market is the same as with the ST FTR market. The principles underlying the LT FTR market are largely the same as the ST FTR market. The differences, where relevant to the analysis, are described.

This chapter proceeds as follows. Section 2 describes the considerations that are relevant to LT FTRs that are not relevant to ST FTRs (and were, therefore, omitted from consideration in chapter V). Section 3 reviews the data used in the analysis. Section 4 describes, with significant reference to chapter V, the econometric models estimated, hypotheses tested, and methodologies employed in the subsequent econometric analysis. Section 5 reports discussion of econometric results. Section 6 concludes.

2. Additional considerations

The key consideration related to LT FTRs that is not relevant to ST FTRs is that succeeding LT FTRs are valid for periods of time that overlap preceding LT FTRs. The process that gives rise to this characteristic is described in section 2.1. The theoretical impact of this characteristic of the data is described in 2.2.

2.1. Auction market

The auctions for LT FTRs valid over quarters q , $q+1$, $q+2$, and $q+3$ are conducted in the second month of quarter $q-1$. These are all two-round auctions in which 25% of available FTRs are sold in the first round, with the remaining 75% sold in the second round. This process facilitates price discovery, which is more meaningful in the context of long-term validity periods than of short-term validity periods. The mechanism used in each round is identical to that used in the single-round ST FTR auctions.

2.2. Overlapping data

Define h , an integer, to be the sampling (observation) interval. Following Hansen and Hodrick (1980), using equations (V-19) and (V-20), the error, along with its h -period update, can be written as

$$\varepsilon_{t+k} = s_{t+k} - E[s_{t+k}|\Phi_t] \quad (\text{VI-1})$$

and

$$\varepsilon_{t+h+k} = s_{t+h+k} - E[s_{t+h+k}|\Phi_{t+h}] \quad (\text{VI-2})$$

The expectation of the product of equations (VI-1) and (VI-2) is zero only if $k \leq h$, that is,

$$E[\varepsilon_{t+k} \varepsilon_{t+h+k}] = 0 \text{ if } k \leq h \quad (\text{VI-3})$$

In other words, the errors from equation (V-19) will be serially uncorrelated only if the duration of the forecast interval, k , is less than or equal to the duration of the sampling interval, h .

In the case where $k = 1$, forward prices are hypothesised to be unbiased forecasts of next-period spot prices and the associated errors will be autocorrelated. Sampling from

each period, that is, $h = 1$, would generally be unproblematic and would be desirable if data are available. The data in this case are said to be non-overlapping. As described in chapter 5, data associated with ST FTRs are of this type as the forecast and sampling intervals are each one month in length.

If $k > 1$, forward prices are hypothesised to be unbiased forecasts of k -period-ahead spot prices while it is not definitionally the case that the associated errors will be autocorrelated. If the sampling interval is smaller than the forecast interval, that is, if $k > h$, the data are said to be overlapping and consequently the errors will be serially correlated as equation (VI-3) no longer holds.¹²¹ In fact, the associated error would follow a moving-average process of order $k/h - 1$. See Frankel (1980) and Kavussanos, Visvikis, and Menachof (2004). As described in section 2.1, data associated with LT FTRs are of this type as the related sampling intervals are one (calendar) quarter in length while forecast intervals are four quarters in length. Thus, OLS estimation of equation (V-19) would result in autocorrelated residuals that follow a MA $(3 = 4/1 - 1)$ process. Such estimates, while being unbiased, would not be efficient.

There are a number of potential ways to address the autocorrelation issue, two of which are considered here. First, standard errors that are heteroskedastic- and autocorrelation-consistent could be estimated. Second, the analysis could be restricted to the use of every k/h^{th} observation only. The resulting data set would be comprised of the largest possible number of observations that do not overlap, thereby mitigating the impact of autocorrelation. In the context of the LT FTR data set, as only every fourth observation would be used for analysis, this approach would result in three-quarters of the data set

¹²¹ Even with $k > 1$, if the sampling interval is greater than or equal to the forecast interval, that is, if $1 < k \leq h$, the data would be non-overlapping and the errors would remain serially uncorrelated. In fact, if the forecast and sampling intervals were normalised by a factor of $(1/k)$, this case would not be different from the case where $k = 1$.

going unused. Results associated with each approach are reported below.

3. Data

This section describes the data used in the analysis of LT FTRs.

3.1. Timeframe and the overlapping nature of the data

Data used in the analysis of LT FTR market performance cover the period from July 2002 to December 2010, inclusive. This period is 34 consecutive calendar quarters in duration. As defined in section 2, LT FTRs are valid for all hours of four consecutive calendar quarters. As a result, the timeframe over which data are observed results in 31 overlapping annual rights periods.¹²² Since the LT FTR auction structure described in section 2 has been consistently adhered to from market opening in 2002 to the end of 2010, there is no loss of data due to evolving auction market structure that is analogous to ST FTRs as described in the previous section.

A convention of referring to the time dimension of a LT FTR by the name of the first calendar quarter for which it is valid is adopted. For instance, a LT FTR purchased at auction in November, 2009 would be valid for the period January 1, 2010 to December 31, 2010 and would be labelled 2010 Q1. In fact, 2010 Q1 constitutes the last observation in the time series dimension of the data set.

3.2. Limitations of analysis due to missing data

As described in Appendix V-C, there are 17 transmission paths connecting Ontario with neighbouring jurisdictions. Analogously to ST FTRs, there are quarters in which no LT

¹²² The overlapping nature of the rights periods mean that each quarter—other than the first and last three—is covered by four distinct LT FTRs. The first and last quarters are covered by only one LT FTR period each, while the second (third) and second- (third-) last quarters are covered by two (three) LT FTR periods each.

FTRs are available to be auctioned. In such an event, no MCP is observed for that particular path and the observation is said to be missing. Other data for the path are still observed, including congestion. A path-by-path summary of the extent of missing data is provided in Table VI-1.

Of the complete set of transmission paths listed in Table VI-1, it is apparent there are insufficient data regarding each direction of the path connecting Ontario to Quebec AT to be of meaningful use in this analysis.¹²³ No further analysis regarding these paths is undertaken and the two observations identified in Table VI-1 as being related to Quebec

Table VI-1: LT FTR: Path-by-path summary of missing observations

Path	# of Present Observations (maximum = 31)	# of Missing Observations	Proportion Missing
† MBSI to ONZN	26	5	0.161
† MISI to ONZN	25	6	0.193
† MNSI to ONZN	24	7	0.226
† NYSI to ONZN	25	6	0.193
PQAT to ONZN	1	30	0.968
† PQBE to ONZN	31	0	0.000
† PQDA to ONZN	31	0	0.000
† PQDZ to ONZN	29	2	0.065
† PQPC to ONZN	31	0	0.000
† PQXY to ONZN	30	1	0.032
† ONZN to MBSI	21	10	0.323
† ONZN to MISI	23	8	0.258
† ONZN to MNSI	23	8	0.258
† ONZN to NYSI	23	8	0.258
ONZN to PQAT	1	30	0.968
† ONZN to PQDA	23	8	0.258
† ONZN to PQHZ	30	1	0.032

¹²³ The Quebec AT transmission line entered service in July 2009. As of January 2011 there had been only one complete annual rights period. As such, there is only one observation in the data set.

AT are removed from the data set. The other paths, for which a minimum of approximately 75% of observations are present, are retained for further analysis and are identified with a dagger (†) at the left-side of the path name column.

Analogous to ST FTRs, quarters for which there were no auctions—and therefore no MCPs—are excluded from the analysis. Given the relatively small time period over which LT FTRs are observed, the possibility of missing observations can complicate the econometric estimation of various models below. For this reason, the set of paths under consideration will be refined further as necessary.

3.3. Profitability of LT FTR ownership

A histogram of the rates of return to LT FTRs is provided in Figure VI-1, where, analogous to Figure V-1, import paths are distinguished from export paths and the left-most vertical bars represent those FTRs returning a zero payout to their holders. Tables VI-2 and VI-3 report statistics regarding rates of return and cumulative returns to LT FTRs, respectively.

The distributions of import and export rates of return are both highly right-skewed, with the approximately 60% of import observations and 40% of export observations being negative. These proportions are less than those observed in the ST FTR data.

Considered on a path-by-path basis, mean rates of return are generally positive, the exceptions being both directions on the Quebec DA path and the import direction on the Quebec HZ path (for which there is no corresponding export path), and always greater than the corresponding medians. The mean and median rates of return are positive on each direction of the paths connecting Ontario to Michigan, Minnesota, and New York, though rates are uniformly higher in the export direction.

Figure VI-1: Distribution of rates of return to LT FTRs, by imports/exports

As captured by the right-most vertical bars of the Figure VI-1, there are a relatively small number of very high observations of rate of return. These few observations materially affect the mean but not the median. The largest recorded rate of return was 170.5 and was associated with the 2004 Q2 FTR on the Ontario to Quebec HZ path. The payout was \$26,114.64 while the MCP was only \$152.50.¹²⁴ The second highest recorded rate of return was 141.3 and was associated with the 2006 Q3 FTR on the Quebec PC to Ontario path. These large rates of return result in mean rates of return on their respective paths being much greater than the means observed on other paths.

Statistics regarding cumulative return are reported in Table VI-3. As established in the

¹²⁴ This is the weighted average MCP as determined by equation (V-28). The first- and second-round MCPs were \$177.00 and \$144, respectively.

Table VI-2: Average and median rates of return to LT FTRs
Units defined as in Table V-4

Neighbouring Jurisdiction	Import Path			Export Path		
	Mean	Median	% < 0	Mean	Median	% < 0
Manitoba	1.85	1.47	0.269	1.69	-0.08	0.524
Michigan	3.31	0.50	0.440	3.64	1.27	0.304
Minnesota	3.02	0.76	0.292	8.84	2.10	0.304
New York	3.36	0.27	0.480	2.56	1.27	0.348
Quebec BE	5.70	0.65	0.452	—	—	—
Quebec DA	-0.86	-0.98	0.968	-0.74	-0.99	0.826
Quebec DZ	0.20	-0.72	0.828	—	—	—
Quebec HZ	—	—	—	13.44	1.02	0.200
Quebec PC	10.59	-0.91	0.774	—	—	—
Quebec XY	1.35	-0.99	0.800	—	—	—
All Paths	3.22	-0.54	0.607	5.37	0.46	0.406

Note: “—” indicates that the transmission path does not exist.

Table VI-3: Cumulative return to LT FTRs
Units defined as in Table V-4

Neighbouring Jurisdiction	Import Path	Export Path
Manitoba	1.041	-0.618
Michigan	0.411	3.285
Minnesota	0.955	2.298
New York	0.987	1.298
Quebec BE	2.531	—
Quebec DA	-0.858	-0.802
Quebec DZ	0.815	—
Quebec HZ	—	0.989
Quebec PC	3.589	—
Quebec XY	-0.621	—
All Paths	0.681	1.582

Note: “—” indicates that the transmission path does not exist.

discussion of ST FTRs, this measure of return is significantly less sensitive to extreme observations. In fact, while the mean rate of return on the Minnesota to Ontario path was 8.84, the cumulative return was 2.298. The highest cumulative return was related to the Quebec PC import path. FTRs on this path include the one that generated, as discussed above, the second highest rate of return observed. That particular FTR received a large weight in the cumulative return calculation because the associated auction produced a relatively large amount of revenue.

3.4. Basic relationship between MCP and payout

Summary statistics regarding the MCP and payout for the paths under consideration—collectively and individually—are reported in Tables VI-A1, VI-A2, and VI-A3 in Appendix VI-A. Table VI-A4 reports summary statistics for realised FTR profits. Table VI-A5 reports the correlation coefficient between the MCP and the payout, along with a test for statistical significance. Table VI-A6 reports summary statistics for various additional variables.

Figure VI-A1 provides a scatter plot of the MCP and payout for the paths under consideration, with MCP equals payout lines superimposed. Figures VI-A2 and VI-A3 illustrate the same data on a path-by-path basis. Figures VI-A4 and VI-A5 illustrate the same data as time series plots. These figures are reported in Appendix VI-A as well.

Across all paths collectively, payout ranges from \$0.00 to \$72,793.44 while MCP ranges from \$13.75 to \$42,779.70 and mean payout exceeds mean MCP. This corresponds to a mean FTR profit of \$3,373.29 as reported in Table VI-A4. Both payout and MCP are right-skewed.

On an individual path basis, mean payout exceeds mean MCP on all paths except the import paths from Quebec DA and XY and the export paths to Manitoba and Quebec

DA. These are the four paths with negative mean FTR profits. All path-level payout and MCP distributions are right-skewed, with neither one systematically more so. The import paths from Manitoba, Michigan, Minnesota, Quebec BE and DZ, as well as the export paths to New York and Quebec HZ have always been characterised by strictly positive payouts. The highest import path payout and MCP were recorded on the Minnesota path, while the highest export path payout and MCP were recorded on the New York path.

The highest priced FTR that generated a payout of zero had an MCP of \$2,446.50 and was valid from 2002 Q3 to 2003 Q2 on the Ontario to Minnesota path. It was the first LT FTR available on that path (or any other). The most profitable FTR, which generated a profit of \$66,426.91, was valid on the Minnesota to Ontario path during the period 2005 Q2 to 2006 Q1 while the least profitable FTR, which generated a loss of \$40,446.43, was valid on the Ontario to Quebec HZ path during the period 2006 Q1 to 2006 Q4. Two-thirds of paths are characterised by right-skewed profit distributions while the remaining one-third are left-skewed.

With respect to the payout-MCP correlation measures reported in Table VI-A5, whenever the coefficient is statistically significant (at, say 5% level of significance) the correlation is a positive number. This includes the case where all paths are considered together. Note the footnote accompanying the table.

As stated, Figures VI-A4 and VI-A5 illustrate payout and MCP in a manner that easily reveals the extent of missing data on an individual path basis as discussed in relation to the ST FTR data in chapter V.

3.5. Benefits of a two-round auction structure

The purpose of this section is to describe a simple method of quantifying the benefits of

a two-round auction structure (as opposed to a single-round structure).

As described above, LT FTRs are auctioned in two stages with approximately one-quarter of the available rights auctioned in the first round and three-quarters in the second round. In the analysis above, the MCP used was defined by equation (V-28), a weighted average. However, at the time of the second-round auction, some details regarding first-round auction outcomes, including the MCP on all FTR paths, have become publically known. As well, first-round bidders know if their own bids were successful. This can be thought of as an information discovery process inherent to two-round auctions not obtainable in single-round auctions.

The simplest test to determine whether meaning discovery occurred between the two rounds is to consider whether the second-round MCP is systematically nearer to the realised payout than the first-round MCP, that is, whether the absolute value of the forecast error associated with the second-round MCP is smaller than the absolute value of the first-round MCP forecast error.

Define the absolute value of the forecast error associated with the MCP from the first-round auction:

$$Error1 = | Payout - MCP1 | \quad (VI-4)$$

with an analogously defined term for the second-round forecast error. Define the difference between the two (absolute valued) forecast errors to be the second-round price discovery:

$$Discovery = Error1 - Error2 \quad (VI-5)$$

A necessary condition for the second-round MCP providing a systematically better forecast of realised payout is that the discovery term defined by equation (VI-5) be

Table VI-4: Second-round price discovery
Average dollars per FTR

Path	N	Payout	MCP1	MCP2	Error1	Error2	Discovery
All paths considered	395	6,732.34	3,159.08	3,425.71	5,607.72	5,460.83	146.89
MBSI to ONZN	26	9,075.92	3,642.75	4,444.21	6,399.89	6,780.30	-380.42
MISI to ONZN	25	12,351.10	8,918.32	8,303.92	10,400.12	10,043.89	356.23
MNSI to ONZN	24	25,272.68	12,517.08	13,287.99	21,067.16	21,094.17	-27.01
NYSI to ONZN	25	4,590.95	2,471.78	2,939.73	4,590.36	4,703.96	-113.60
PQBE to ONZN	31	1,993.34	689.79	479.95	2,099.53	2,059.26	40.27
PQDA to ONZN	31	37.51	262.49	261.25	232.17	232.75	-0.57
PQDZ to ONZN	29	761.59	436.59	417.76	968.97	870.52	98.45
PQPC to ONZN	31	1,479.16	382.61	291.08	1,649.86	1,574.42	75.45
PQXY to ONZN	30	116.78	232.77	218.76	288.63	286.48	2.16
ONZN to MBSI	21	326.21	772.88	824.37	854.98	869.72	-14.74
ONZN to MISI	23	5,554.36	1,258.71	1,336.32	4,530.45	4,446.52	83.93
ONZN to MNSI	23	11,163.04	2,299.55	2,886.41	10,240.39	9,533.71	706.67
ONZN to NYSI	23	15,284.81	6,895.50	7,330.62	10,731.99	10,329.23	402.76
ONZN to PQDA	23	62.58	284.21	290.51	259.14	255.70	3.43
ONZN to PQHZ	30	17,148.89	8,124.47	9,906.75	13,253.70	12,294.04	959.65

positive.

Table VI-4 reports the mean value of discovery, along with certain other applicable variables, for all paths collectively and each path under consideration individually.

The mean value of price discovery across all auctions is \$146.89, that is, the second-round MCP is, on average, approximately \$147 nearer to the realised payout than is the first-round MCP. With respect to individual import paths, this result does not hold consistently, with four of nine paths reporting negative price discovery. With respect to individual export paths, the positive average discovery result is more consistent and larger, with negative discovery observed only on the path to Manitoba.

*Table VI-5: Summary statistics regarding second-round discovery and related t-test
Average dollars per FTR*

Path	N	Mean	Std. Dev.	p-value
All paths considered	395	146.89	2,376.36	0.220
MBSI to ONZN	26	-380.42	2,270.68	0.401
MISI to ONZN	25	356.23	2,136.38	0.413
MNSI to ONZN	24	-27.01	3,164.16	0.967
NYSI to ONZN	25	-113.60	1,284.26	0.662
PQBE to ONZN	31	40.27	610.12	0.716
PQDA to ONZN	31	-0.57	183.14	0.986
PQDZ to ONZN	29	98.45	394.43	0.190
PQPC to ONZN	31	75.45	243.04	0.094
PQXY to ONZN	30	2.16	81.09	0.885
ONZN to MBSI	21	-14.74	210.44	0.752
ONZN to MISI	23	83.93	491.43	0.422
ONZN to MNSI	23	706.67	1,987.84	0.102
ONZN to NYSI	23	402.76	1,453.90	0.198
ONZN to PQDA	23	3.43	166.12	0.922
ONZN to PQHZ	30	959.65	7,229.38	0.473

Notwithstanding the determination that average second-round price discovery is positive over all paths collectively, as well as on ten of the fifteen paths individually, this is not, in and of itself, evidence that discovery differs from \$0.00 systematically. Table VI-5 reports summary statistics regarding the distribution of discovery, as well as the p-value corresponding to a t-test with the null hypothesis that discovery equals zero. This null hypothesis is identical to one in which the first-round forecast error equals that of the second-round.

Given the relatively large standard deviations reported in the fourth column of Table VI-5, it is not surprising that the null hypothesis cannot be rejected in any of the cases under consideration.

In concert with the observation that some of the paths are individually characterised by negative second-round discovery, the lack of statistical significance of those remaining paths suggests there is little evidence that market participants gain meaningful information from the results of the first-round auction for use in the second round.

3.6. Incidence of censoring

Censored observations are easily distinguished from uncensored observations upon examination of Figures VI-A1, VI-A2, and VI-A3. Table VI-6 reports the incidence of LT FTR censoring on each of the paths identified with a dagger (†) in Table VI-1. Quarters without auctions are not considered to be censored. As censoring is not the principal issue under consideration with respect to LT FTRs, paths with more than five censored observations are excluded from further analysis. The remaining 12 paths are identified

Table VI-6: LT FTR: Incidence of censoring for paths

Path	Number of Auctions	Number of Payouts Censored	Proportion of Payouts Censored
†† MBSI to ONZN	26	0	0.000
†† MISI to ONZN	25	0	0.000
†† MNSI to ONZN	24	0	0.000
†† NYSI to ONZN	25	1	0.040
†† PQBE to ONZN	31	0	0.000
PQDA to ONZN	31	13	0.419
†† PQDZ to ONZN	29	0	0.000
†† PQPC to ONZN	31	4	0.129
PQXY to ONZN	30	10	0.333
†† ONZN to MBSI	21	5	0.217
†† ONZN to MISI	23	3	0.130
†† ONZN to MNSI	23	1	0.043
†† ONZN to NYSI	23	0	0.000
ONZN to PQDA	23	8	0.348
†† ONZN to PQHZ	30	0	0.000

with two daggers (++) in Table VI-A1. Of the 311 FTRs observed on these 12 paths, approximately 4.5% were censored.

The 12 paths characterised by relatively low rates of censoring are those that will be considered for econometric analysis below.

3.7. Stationarity

It is apparent from Figures VI-A4 and VI-A5 that time series stationarity may be a significant concern in any analysis of LT FTRs. Presuming a stable relationship between payout and MCP exists, analysis of stationarity will focus on the properties of the payout time series because there are no missing observations to complicate the analysis. The proportion of missing observations was discussed above.

Table VI-7 reports results of the application of various unit root tests to the data described. A modified Dickey-Fuller unit root test (DFGLS) is applied to each series.¹²⁵

The results of this test are reported in column 3. In the event the DFGLS test implies the series has a unit root, the Zivot-Andrews (1992) procedure which allows for a single structural break is implemented. The results of this procedure are reported in column 4, with the corresponding break point reported in column 5. If the DFGLS test suggests the time series is stationary, allowance for structural breaks via the Zivot-Andrews procedure is unnecessary and “—” is reported in columns 4 and 5. Column 6, the right-most column, reports the combined results of the application of both, if necessary, unit root tests to the data series. There are three possible results: (a) “UR”: unit root with and without allowance for a structural break; (b) “Stat.”: the series is stationary without

¹²⁵ The test is modified in the sense that the time series is transformed by a generalized least-squares regression. The maximum number of lags, k , is determined by the Schwert criterion in which $k = \{12 * ((T + 1)/100)^{(0.25)}\} = 9$ for this time series. The optimal lag length is determined by the Ng-Perron sequential t-test.

Table VI-7: LT FTR: Stationarity

Path	N	DFGLS	Zivot-Andrews		Result
		Tau-statistic	Min. t-stat	Break point	
MBSI to ONZN	26	-3.227*	-6.240***	27	Stat. w Break
MISI to ONZN	25	-2.256	-8.177***	13	Stat. w Break
MNSI to ONZN	24	-2.127	-6.273***	13	Stat. w Break
NYSI to ONZN	25	-0.963	-17.087***	27	Stat. w Break
PQBE to ONZN	31	-5.904***	—	—	Stat.
PQDZ to ONZN	29	-0.624	-4.630	10	UR
PQPC to ONZN	31	-5.814***	—	—	Stat.
ONZN to MBSI	21	-3.876***	—	—	Stat.
ONZN to MISI	23	-1.784	-7.126***	22	Stat. w Break
ONZN to MNSI	23	-6.334***	—	—	Stat.
ONZN to NYSI	23	-3.231*	-5.874***	22	Stat. w Break
ONZN to PQHZ	30	-5.662***	—	—	Stat.

Note: * $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$

allowance for a structural break; and (c) “Stat. w break”: the series is stationary if a structural break is permitted.

Eleven of the twelve paths are characterised by stationary payout series, six of them once allowing for structural breaks. One series possess a unit root regardless of the allowance for a single structural break. These distinctions are useful when considering further analysis of LT FTRs.

4. Econometric models, hypotheses, and methodology

4.1. Econometric models and hypotheses

The econometric models and hypotheses are the same as in chapter V.

4.2. Methodology

With LT FTR panel data, equation (VI-29) is estimated using regressor configurations I and III—the rationale for which is described below. With overlapping observations in the data set, the pooled OLS estimator is applied, followed by the standard fixed- and random-effects estimators. The results are then compared. Each of these estimators is then applied to a modified data set constructed such that observations are not overlapping.

5. Results and discussion

Table VI-8 summarises the estimation approaches implemented with panel data regarding LT FTRs.

This section focuses on the estimation of regression equation (VI-29) with LT FTR panel data. Unless otherwise stated, statistical significance in the discussion that follows refers to a 95% level of confidence.

Given the overlapping nature of LT FTRs, the convergence terms and the one-period lag of profit term discussed in chapter V are not considered in relation to LT FTRs. Thus, only regression configurations I and III, as defined in Table V-8, are considered. Given

Table VI-8: LT FTR: Summary of econometric approaches using panel data

Brief Description of Econometric Approach	Appendix	Tables
Pooled cross-section with overlapping observations	VI-B	B1 – B2
Fixed-effects with overlapping observations	VI-B	B3 – B4
Random-effects with overlapping observations	VI-B	B5 – B6
Comparison of FE and RE with overlapping observations	VI-B	B6
Pooled cross-section with non-overlapping observations	VI-B	B8 – B9
Fixed-effects with non-overlapping observations	VI-B	B10 – B11
Random-effects with non-overlapping observations	VI-B	B12 – B33
Comparison of FE and RE with non-overlapping obs.	VI-B	B14

a high degree of multicollinearity present within the set of contemporaneous regressors in the context of annual data, a restricted set of control variables—the natural gas price and the risk-free interest rate—are included in configuration III.

The two configurations will first be estimated with overlapping data, where the overlapping data issue is ignored, and then with non-overlapping data, where all LT FTRs valid, inclusively, from Q3 of a particular year to Q2 of the subsequent year are used.

5.1. Overlapping observations

Given the overlapping nature of the data used for this component of the analysis, it is anticipated the residuals associated with analysis that ignores this feature of the data will be autocorrelated. This is confirmed by application of Wooldridge's (2002) test for autocorrelation in panel data.¹²⁶ Standard errors calculated without consideration of this issue will be biased, undermining inference drawn from the associated results. For this reason, the results as a base-case are merely noted and no attempt is made to draw inference regarding market performance.

5.1.1. Pooled linear estimator with overlapping observations

Tables VI-B1 and VI-B2 report results associated with the estimation of the two regressor configurations with OLS using overlapping period, pooled cross-section panel data.

The estimates of β , for configurations I and III respectively, are 0.764 and 0.809. Using Huber-White robust standard errors, the respective 95% confidence intervals range from 0.412 to 1.116 and from 0.503 to 1.116. Various econometric issues

¹²⁶ See Wooldridge (2002), pp. 282-3, and Drukker (2003) for details regarding this test.

notwithstanding, it can be concluded that β is statistically positive, thereby rejecting hypothesis B, but not different from 1, thereby failing to reject hypothesis C, for both configurations. Moreover, it can be concluded that the intercept differs from 0, though not with the same sign, for the two cases. As a result, the joint informational efficiency hypothesis is rejected for each case.

Of the two configurations, III appears to fit the data better than I: its adjusted R-square is higher, while AIC and BIC are lower. As well, the addition of the control variables appears to diminish the specification error suggested by the Linktest procedure regarding configuration I. As stated above, due to the unresolved autocorrelation issue, no attempt is made to draw inference from these results regarding LT FTR market performance.

5.1.2. Fixed- and random-effects estimator with overlapping observations

As with ST FTR data, LT FTR data are generated on different transmission paths and so it may not be appropriate to pool all data into a single cross-section. To that end, applications of standard fixed- and random-effects estimators are considered, beginning with fixed effects.

Fixed-effects/LSDV estimator with overlapping observations

Econometric results associated with the application of the standard fixed-effects estimator are reported in Tables VI-B3 and VI-B4. The contents of these tables broadly correspond to those reported in Tables VI-B1 and VI-B2.

The point estimates of β for the two configurations are 0.249 and 0.309, with associated 95% Huber-White robust confidence intervals ranging from -0.317 to 0.815 and -0.125 to 0.743, respectively. As a result, it can be concluded that β does not differ from 0, thereby failing to reject hypothesis B, while it is less than 1, thereby rejecting hypothesis

C, for each configuration. The intercept in configuration I is positive and statistically significant, while it does not differ from 0 for configuration III. Nevertheless, the joint informational efficiency hypothesis, hypothesis D, is rejected for both configurations.

Each of the configurations of regressors is jointly significant, as are both sets of fixed effects.

Random-effects estimator with overlapping observations

Results associated with application of the standard random-effects estimator are reported in Tables VI-B5 and VI-B6.

The point estimates of β for the two configurations are 0.705 and 0.651, with confidence intervals ranging from 0.409 to 1.001 and 0.418 to 0.884, respectively. The estimate of β is significantly greater than 0 for each configuration, while it is less than 1 for configuration III and nearly less than 1 for configuration I (and would be so at a 94% level of confidence). The intercept is statistically positive for configuration I, but does not differ from 0 for configuration III. Taken together, joint informational efficiency hypothesis, hypothesis D, can be rejected for each configuration.

Each set of regressors is statistically significant, as is each random-effect term.

Comparison of fixed- and random-effects approaches with overlapping observations

The fixed-effects estimator is always consistent. Under a null hypothesis of no correlation between the random-effects and the regressors the random-effects estimator is consistent as well. The random-effects estimator is preferred to the fixed-effects estimator as it is efficient. Under the alternative hypothesis—where the random-effects terms are correlated with the regressors—the random-effects estimator is inconsistent and the fixed-effects estimator is preferred. The Hausman test can be used to test the

null hypothesis. This issue was discussed in greater detail in relation to the ST FTR analysis above.

Results of the Hausman test are reported in Table VI-B7. For both configurations the fixed-effects estimator is preferred.

5.2. Summary of results of panel data analysis of LT FTRs with overlapping observations

The analysis above suggested a preference for the fixed-effects approach over both the random-effects and pooled cross-section approaches. The general result of that analysis, as discussed above, is that β is less than 1 but not different from 0. Moreover, the intercept was found to either 0 or positive, depending on the regressor configuration. Overall, these results are inconsistent with a finding of either informational efficiency or forward market unbiasedness.

5.3. Non-overlapping observations

The simplest mechanism for avoiding the overlapping observations issue is to select the largest subset of observations that do not overlap. With annual data observed at a quarterly frequency, this would amount to restricting the data set to every fourth observation on each transmission path. The analysis proceeds with data covering, inclusively, the period Q3 of each year to Q2 of the subsequent year.

5.3.1. Pooled linear estimator with non-overlapping observations

Tables VI-B8 and VI-B9 report results associated with the estimation of the same two regressor configurations as above—I and III—with OLS using non-overlapping periods, pooled cross-section panel data. The four tables report, respectively, coefficient estimates and certain summary statistics, various diagnostic tests, hypothesis test

results, and 95% confidence intervals for the coefficients associated with the MCP. The estimates of β , for configurations I and III respectively, are 0.845 and 0.847, with associated confidence intervals ranging from 0.152 to 1.538 and 0.258 to 1.435. As a result, it is concluded for both cases that β is statistically positive, thereby rejecting hypothesis B, but not different from 1, thereby failing to reject hypothesis C.

For configuration I the intercept is statistically negative, thereby rejecting hypothesis A, and with the results regarding β , the joint informational efficiency hypothesis, hypothesis D, is also rejected.

For configuration III the intercept does not differ statistically from 0, thereby failing to reject hypothesis A, and with the results regarding β , the joint informational efficiency hypothesis, hypothesis D, is also not rejected.

As reported in Table H13, while both sets of regressors are jointly statistically significant, adjusted R-square and AIC suggest that configuration III is preferred to I. As well configuration III also appears to be a preferable specification.

5.3.2. Fixed- and random-effects estimator with non-overlapping observations

Given the numerous distinct transmission paths under consideration, pooling may not yield consistent econometric estimates. As a result, fixed- and random-effects estimators are considered as alternatives.

Fixed-effects/LSDV with non-overlapping observations

Econometric results associated with application of the standard fixed-effects estimator are presented in Tables VI-B10 and VI-B11. The contents of these tables broadly correspond to the contents of Tables VI-B8 and VI-B9.

While the set of all regressors is statistically significant for configuration III, the

converse is true for configuration I. As a result, only configuration III considered further. Use of non-overlapping observations has ameliorated the autocorrelation issue, that is, a null hypothesis of no autocorrelation is not rejected by Wooldridge's (2002) test. Huber-White robust standard errors are calculated and used in the remainder of this analysis.

Notwithstanding the finding that the regressors are jointly statistically significant, the set of fixed effects themselves are not jointly statistically significant. Nevertheless, the point estimate of β for configuration III is 0.325, with an associated 95% confidence interval ranging from -0.624 to 1.273. While it cannot be concluded that β differs from 1, thereby failing to reject hypothesis C, it also cannot be concluded that β differs from 0, thereby failing to reject hypothesis B. However, at a lower level of confidence, say 90%, it would be concluded that β is less than 1 though still not different from 0. The intercept does not differ statistically from 0. Taken together, the joint informational efficiency hypothesis, hypothesis D, cannot be rejected. It should be noted that these results are dependent on the very large standard errors associated with the various coefficient estimates.

Random-effects estimator with non-overlapping observations

Results associated with application of the standard random-effects estimator are reported in Tables VI-B12 and VI-B13. These tables report, respectively, coefficient estimates and certain summary statistics, hypothesis test results, and 95% Huber-White robust confidence intervals.

The estimated standard error of the random-effects term is 0 for each configuration. As a result, the random-effects estimator degenerates into the pooled OLS estimator, and so the results reported in Tables VI-B12 and VI-B13 are equivalent to those reported in Tables VI-B10 and VI-B11. This result is confirmed by the Breusch-Pagan test of the

significance of the random-effects term.

As discussed above, application of the pooled cross-section OLS estimator—in which configuration III was preferred—did not suggest the rejection the joint informational efficiency hypothesis, hypothesis D.

Comparison of fixed- and random-effects approaches with non-overlapping observations

Results of the applicable Hausman test are reported in Table VI-B14. The fixed-effects estimator is preferred for both configurations, though it should be recalled that configuration III was preferred in the fixed-effects analysis itself.

5.3.3. Summary of results of panel data analysis of LT FTRs with non-overlapping observations

The analysis above suggested a preference for the fixed-effects approach over the random-effects approach, though the fixed-effects terms were not found to be jointly statistically significant in either configuration.

While the fixed-effects approach led us to *not* reject the joint informational efficiency hypothesis, it was not possible to conclude that β differed from either 0 or 1 at a 95% level of confidence. Thus, while there is some evidence in favour of a finding of informational efficiency, it is undermined by the large magnitude of the standard errors. Moreover, at a somewhat lower level of confidence, say 90%, these informational efficiency findings were rejected outright.

6. Conclusions

Analysis of the LT FTR market involved 15 distinct transmission paths connecting Ontario with its neighbours. Averaged across all paths, a positive and statistically

significant correlation between the MCP and payout was observed. While under formal econometric analysis the joint informational efficiency hypothesis was not rejected, large standard errors also resulted in the inability to conclude there was a non-zero relationship between the MCP and payout, thereby undermining the above conclusion.

With respect to the two-round nature of LT FTR auctions, while it was determined that the second-round price was, on average, about \$147 closer to the eventual payout than the first-round price, suggesting there are potential benefits associated with this auction structure, this value was not statistically significant. With respect to the various learning hypotheses, the evidence was mixed.

6.1. Future research

There are many potential directions for future research regarding FTRs.

For instance, with respect to the analysis of LT FTR markets a dynamic model specification could be adopted in an attempt to ameliorate the impact of overlapping observations causing serial correlation. Such dynamic models require use of Arellano-Bond-type GMM estimators that are meaningfully different from the techniques employed in this chapter.

As well, alternative panel data specifications could be estimated. For instance, there are time-invariant characteristics—such as import/export intertie direction dummy variables, Canada-specific intertie dummy variables, or average number of auction bidders.

With respect to the analysis of ST FTR markets, better instruments would allow the endogeneity problem to be better handled. This may help to reduce the large magnitude of standard errors that limited the ability to draw conclusions.

It may also be useful to consider relaxing certain assumptions regarding the behaviour of market participants, in particular, that they are risk neutral when this may not be the case.

Chapter VII: Bidding in financial transmission rights auctions

1. Introduction

A financial transmission right (FTR) is a financial instrument that entitles its owner to receive a payment related to the degree of realised congestion on a particular path in the (physical) transmission system during a prescribed period of time. In the context of Ontario's electricity market, FTRs are available for 17 distinct transmission paths that connect the province's electricity grid to its neighbours. FTR ownership is obtained by participation in auctions held by the transmission system operator, which in Ontario is known as the Independent Electricity System Operator (IESO). These auctions are held periodically—monthly in the case of short-term FTRs and quarterly in the case of (annual, overlapping) long-term FTRs—though not necessarily in every month or quarter. The auction market clearing price is the bid price of the lowest accepted bid. Given the overlapping nature of long-term FTRs, this type of FTR is not analysed here. Thus, the analysis focuses exclusively on short-term FTRs. A detailed description of FTRs, including the definition of congestion and the process by which it is measured, is provided in section 2 of chapter V.

The intent of this chapter is to analyse the determinants of the number of bidders that decide to participate in FTR auctions. An economic agent is defined to be a bidder if they bid for at least one FTR.¹²⁷ The number of bidders is expected to be dependent upon the competitiveness of the relevant external market, the number of rights available for sale, recently observed levels of congestion, and various unobserved effects. It is expected that transmission lines connecting Ontario's market to competitive external markets are subject to more competition for capacity and, therefore, more competition in the associated FTR auction markets. Larger markets,

¹²⁷ Bid prices must be strictly positive, *i.e.*, at least \$0.01, to be accepted.

that is, larger numbers of available rights, are expected to induce more economic agents to contest the market. The level of recently observed congestion is expected to signal prospective bidders to the potential of the market. In particular, if there has been little recent congestion on a path, there are expected to be few economic agents that follow and are interested in FTRs for that path. As a result, there are fewer possible bidders at auction. If, on the other hand, there has been a significant amount of congestion on a path, there are expected to be relatively many economic agents that follow and are interested in the FTRs for that path (either to make profit or to hedge congestion risks).¹²⁸

The issue of prices bid by these economic agents is not considered. Such issues are of a very different nature as they would require consideration of the factors that determine the level, *i.e.*, prices and quantities, at which bids are made.

The number of bidders has a special characteristic that merits use of an econometric estimation technique designed for such data. The number of bidders in every FTR auction is, definitionally, a non-negative count variable. Since every FTR auction that has been held in Ontario has been contested by at least one bidder, the observed number of bidders is in fact a positive count variable. The standard techniques employed when the dependent variable is of this nature, aside from linear models, are the Poisson and negative binomial regression models. The manner in which the number of bidders is dispersed renders the negative binomial regression model inapplicable. An alternative regression framework that admits this characteristic—based on the gamma distribution—is considered.

Evidence in support of the role of the external market as well as the number of rights

¹²⁸ Put another way, few economic agents are expected to be concerned with constraints that rarely bind. It is the concern that a constraint may bind that should drive interest in the first instance.

available is identified as impacting the number of bidders in the manner expected. Evidence in favour of the role of previous congestion is lacking.

This chapter proceeds as follows. Section 2 reviews existing work that relates to bidding in the FTR market in Ontario. Given the count-nature of the data, a brief review of econometric modelling examples using count-data is also provided. Section 3 provides a description of the economic issues of interest, including hypotheses to be tested and a priori expectations regarding the results. Section 4 discusses the available data. The econometric methodology employed is described in section 5. Model specification is also discussed in section 5. Empirical results and discussion thereof are presented in sections 6 and 7, respectively.

2. Literature review

Two classes of previous analysis are useful to review before proceeding to describe the methodology employed here: analyses of bidding in Ontario's FTR auction market and analyses of count data in non-electricity contexts. Each is considered in turn.

2.1. Bidding in Ontario's FTR auction market

Bidding in Ontario's FTR auction market has not been widely studied and appears not to have been subject to previous econometric analysis. The most extensive analysis conducted to date was reported in the August 2010 report of the Market Surveillance Panel (MSP, August 2010). The data covered the period June 2002 to March 2010, a period of 94 months—the same time period considered in this chapter.

The MSP's analysis was statistical in nature. It reported that, on average since market opening, the number of bidders for FTRs valid on paths to and from Manitoba and Minnesota has averaged between 2 and 2.5. For paths to and from Michigan and New York, the number has averaged approximately 4.

The MSP documented a number of changes in the FTR market since market opening. With respect to bidders, the average number has increased on all export-oriented paths except one (the PQDA path), with an especially noticeable increase on the path to Michigan. With respect to import-oriented paths, the number of bidders remained relatively stable, though not uniformly so. It was stated that the results are consistent with the general increase in export congestion that has appeared over the later years of the analysis (MSP, August 2010, p. 172).

These results suggest the importance of considering a methodological framework that allows for path-specific (including direction) effects, such as path-specific weights, in order to control for differences across external markets.

2.2. Count-data in other contexts

Count-data has been subject to extensive analysis in a variety of settings beyond electricity markets, most often using the Poisson regression model and/or the negative binomial regression model. It is useful to consider what is being counted, though this feature is far from the most important characteristic of the situations in which these models have been applied.

In some cases, the count is of the number of instances in which an individual economic agent—a person, a household, or a firm—undertakes or experiences a particular action or state. For instance, Hausman, Hall, and Griliches (1984) count firms' annual patents filings as a result of undertaking research and development activities. Gurmu and Trivedi (1996) count the number of recreational trips taken by boaters in a particular summer. Deb, Munkin, and Trivedi (2006) count the annual number of doctor visits made by insured and uninsured individuals. In each of these cases, the count is of the number of events experienced by an economic agent.

motivations for these agents' perspective participation in the FTR market.

Recently observed congestion signals the agent about the value of the FTRs to their activities. For instance, low levels of recently observed congestion are expected to signal traders that congestion is of relatively little concern on the path. Independent of all other factors, this is expected to lessen interest in bidding for the FTRs and, therefore, the number of bids. On the other hand, high levels of recently observed congestion are expected to signal traders that congestion is of relatively high concern on the path. Independent of all other factors, this is expected to raise interest in bidding for the FTRs and, therefore, the number of bids.

With respect to modelling, there are at least two ways to measure congestion. First, congestion in a particular month can be measured in dollars and would be calculated as the sum of the ICP over the hours within the month. This is the definition of the variable $Payout_t$ considered in chapter V. Second, congestion could be measured as the proportion of hours in a month in which the transmission capacity constraint binds. The latter measure is likely to be more economically sensible as it is definitionally bounded between 0 and 1, inclusive, and is therefore less likely than the former measure to suffer from problems associated with small numbers of influential observations that may be idiosyncratic in nature, *i.e.*, occasional very high payouts due to rare events in the electricity system. Moreover, it accounts for extent of time during which transmission capacity constraints bind—a key issue for traders and financial-only participants alike.

3.4. Deterministic variables

As described in section 2.1, previous analysis of Ontario's FTR market suggests the importance of considering path-specific effects and/or time-specific effects. These are included as described in section 5.

4. Data and descriptive statistics

This section describes various aspects of the data used in the following analysis.

4.1. Count of auctions

The study period extends over a 94 month range, beginning June 2002 and ending March 2010, inclusive. Note that this time period is a subset of the study period considered in relation to the assessment of the forward market unbiasedness hypothesis reported in chapters V and VI. The reason for this distinction is that auction market bidding data, the number of bidders in particular, is not available on an auction-by-auction basis beyond the 94 month range.

The dataset under analysis is comprised of 722 auctions of short-term FTRs on 17 distinct transmission paths. The number of auctions held in relation to each transmission path is reported in Table VII-1. The number of auctions ranges from a minimum of 3 on the import and export paths from/to PQAT (as noted in chapter V, a recently constructed transmission path) to a maximum of 78 in the import path from

Table VII-1: Number of FTR auctions, by transmission path

Import Paths	# of FTR Auctions	Export Paths	# of FTR Auctions
MBSI to ONZN	78	ONZN to MBSI	37
MISI to ONZN	62	ONZN to MISI	64
MNSI to ONZN	17	ONZN to MNSI	23
NYSI to ONZN	64	ONZN to NYSI	62
PQAT to ONZN	3	ONZN to PQAT	3
PQBE to ONZN	73	ONZN to PQDA	37
PQDA to ONZN	74	ONZN to PQHZ	35
PQDZ to ONZN	34		
PQPC to ONZN	46		
PQXY to ONZN	10		

Figure VII-1: Frequency distribution of the number of bidders

Manitoba. There are seven transmission paths on which there have been at least 60 FTR auctions. The upshot of the data reported in the table is that the number of auctions varies significantly across the transmission paths.

The number of bidders is an integer that ranges from 1 to 11, inclusive. This means that there are no auctions that have been uncontested, *i.e.*, no auctions with zero bidders. A histogram illustrating the number of FTR auctions contested by each number of bidders is provided by Figure VII-1. The labels located at the top of each vertical bar indicate the precise number of auctions contested by each number of bidders.

Table VII-2 reports summary statistics regarding the number of bidders. The mean number of bidders is 2.82, with a standard deviation and variance of 1.34 and 1.82, respectively. The median number of bidders is 2. The relative values of the mean and

Table VII-2: Summary statistics of number of bidders

Statistic	All auctions	Nature of external market	
		Competitive	Non-competitive
Mean	2.82	3.85	2.39
Standard deviation	1.34	1.83	0.75
Variance	1.84	3.35	0.56
Skewness	2.19	1.29	0.87
Median	2	4	2
N	722	212	510

median are related to the data illustrated in Figure VII-1, which suggests that the number of bidders is not normally distributed, instead being right-skewed. Indeed, the skewness is 2.19.

4.2. Structure of external markets

As stated in section 3, consideration of the number of bidders as it relates to the structure of the external market is the most important of the economic relationships being considered in this chapter. Table VII-2 also reports summary statistics regarding the number of bidders for each type of external market structure. Of the 722 FTR auctions held during the study period, 212 of them were for FTRs related to transmission paths connecting Ontario to neighbouring jurisdictions whose market structures were similar to Ontario's, while the remaining 510 were otherwise.¹³⁵ The

¹³⁵ Recall that Michigan and Minnesota's competitive wholesale electricity market (MISO) was established in 1 April 2005. FTR auctions on each path were held both before and after this date. Regarding import-oriented FTRs, there were 23 and 16, respectively, on the Michigan and Minnesota paths before MISO's market opening, and 39 and 1, respectively, after market opening. Regarding export-oriented FTRs, there were 25 and 16, respectively the Michigan and Minnesota paths before MISO's market opening, and 39 and 7, respectively, after market opening. This distinction is accounted for in the data reported in-text and explains why the number of auctions, counted by external market structure, cannot simply be read-off Table VII-1.

mean number of bidders in auctions where the external jurisdiction has a competitive wholesale market is 3.89. Otherwise, the mean is 2.43.¹³⁶ Also, the number of bidders that participate in auctions where the external jurisdiction has a competitive wholesale market is more variable than otherwise.¹³⁷ The most striking difference between the two types of FTRs relates to the median, which is twice as high where the external jurisdiction has a competitive wholesale market compared to otherwise, that is, 4 compared to 2.

While the evidence considered thus far is certainly not conclusive, preliminary consideration of the impact of external market structure on Ontario's FTR market suggests that this variable may control for a meaningful determinant of the number of bidders that decide to participate. This corresponds to the expectations regarding this variable described in section 3.

4.3. Available FTRs

Another variable that is expected to be an important determinant of the number of bidders in the auction market is the number of FTRs available for auction. In the 722 auctions that occurred during the study period, the number of FTRs available for auction ranged from 1 to 1318 with a mean of 197. These data are plotted in Figure VII-2. The figure also shows the linear prediction plot associated with regressing the number of bidders on the number of FTRs available and a constant. As the data reported in the footnote of the figure reveal, there is a statistically significant relationship between the two variables, with the number of available FTRs explaining nearly half of the variation of

¹³⁶ A simple t-test (allowing for unequal variances) of the null hypothesis of the equality of these means against the general alternative can be rejected at greater than the 99% confidence level. In fact, p-value = 0.0000.

¹³⁷ A simple F-test of the null hypothesis of the equality of these variances (actually, the standard deviations), *i.e.*, ratio = 1, against the general alternative can be rejected at greater than the 99% confidence level. In fact, p-value = 0.0000.

In other cases, the count is of the number of instances in which distinct economic agents undertake a particular action or enter a particular state. King (1988) counts the number of members of the United States House of Representatives that changed political affiliations, by Congress, in the nineteenth century. Davutyan (1989) counts the number of bank failures annually in the United States. Both Berrebi and Ostwald (2011) and Kis-Katos, Liebert, and Schulze (2011) count the number of terrorist incidents each year by country. Ichinose and Yamamoto (2011) count the number of instances of illegal dumping of toxic material annually in Japan (they also estimate this number based upon reported events). In each of these cases, the count is of the number of economic agents that experienced an event.

A count of the number of bidders contesting an FTR auction in Ontario is similar to the latter cases.

3. Economic issues of interest

The number of bidders that contest an FTR auction for a particular path is expected to be based on the underlying economic characteristics associated with the path. The characteristics that are useful at explaining the variation of the number of bidders across paths and/or time must vary across paths and/or time. The purpose of this section is to provide a description of a number of these, including a discussion of their hypothesised impact on the number of bidders.

It is expected, in general terms, that the number of bidders that decide to contest a particular FTR auction depends on the nature of the external market, the number of rights available for purchase, recently observed levels of congestion, and unobserved path and time period effects. Each of these is discussed in turn.

3.1. Structure of external market

All transmission paths under consideration are associated with interties that connect Ontario's electricity market to that of a neighbour and allow for electricity to either be exported from or imported to Ontario (or both, but not contemporaneously). As described in chapter V, the structure of the market on the Ontario side of each transmission path is the same, a fact summarised by common market rules and the uniformity of the Ontario wholesale market clearing price across all transmission paths. However, the structures of the external markets are heterogeneous across paths and time. This is one potential source of variation of the number of bidders across FTR auctions.

External markets can be classified into two broad categories based on their structure. First, there are markets similar to Ontario in the sense that they also have competitive wholesale markets as well as open and transparent transmission capacity allocation mechanisms. This category includes the paths to and from New York for the whole study period, and the paths to and from Michigan and Minnesota beginning with April 2005.¹²⁹ Second, there are markets dis-similar to Ontario in the sense that they lack either a competitive wholesale market or an open and transparent transmission capacity allocation mechanism (or both). This category includes the paths to and from Manitoba and Quebec for the whole study period, and the paths to and from Michigan and

¹²⁹ A competitive regional electricity market was established by the Midwest Independent System Operator (MISO) on 1 April 2005 encompassing 10 states in the United States, namely: Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Montana, North Dakota, South Dakota, and Wisconsin. A reliability coordination area is operated by the MISO that includes these 10 states as well as the Province of Manitoba, *i.e.*, Manitoba does not participate in the electricity markets administered by the MISO. See Midwest Independent System Operator (undated, a) and (undated, b) for an overview of MISO's operations and history, respectively.

Minnesota ending March 2005. Thus, the two categories are mutually exclusive.¹³⁰

The relevant issue is whether this characteristic would result in variation of the number of bidders in FTR auctions and why. It is expected that there would be systematically fewer bidders for FTRs associated with transmission paths where the external market structure differs materially from Ontario's, *i.e.*, no competitive wholesale market or open-access transmission system. In other words, it is expected that there would be systematically more bidders for FTRs associated with transmission paths that connect Ontario to similarly structured wholesale markets. There are several reasons for this.

First, in certain cases—Manitoba and Quebec in particular—the structure of the external market takes the form of a vertically integrated, provincially-owned, crown corporation that centrally manages its own transmission system, including dispatching local generation and inter-jurisdictional trade. Due to the amount of control these operators have over the scheduling inter-jurisdictional trade, they also have a significant amount of control over the level of congestion and the corresponding payout that prevails.¹³¹ That is, the external market operator can be thought of as exercising market power in relation to the intertie connecting their market to Ontario's. Since this power can be exercised unilaterally, participants in Ontario's electricity market have good reason to be hesitant about bidding for FTRs on such transmission paths.

It is useful to consider how an external market's vertically integrated monopoly is able to exert its market power. Let Manitoba be the external market in question. Suppose that the transmission path from Ontario to Manitoba was (export) congested. There would be a price wedge between the uniform Ontario wholesale market clearing price and the external zone price equal to the intertie congestion price (ICP). Reflecting the

¹³⁰ These markets may be materially different or similar in other respects. Such issues are beyond the scope of this analysis.

¹³¹ See chapter V for detailed definitions of all of these terms, as well as a numerical example.

purpose of the ICP as a mechanism to ration scarce transmission capacity and allocate it to its highest value uses, the ICP would be positive in order that some fraction of the exports that would have otherwise flowed from Ontario to Manitoba at the uniform Ontario wholesale market clearing price do not flow. As a result, exporters would have to pay both the wholesale market clearing price and the ICP.¹³² The exporter would have to charge at least that much to its customer in Manitoba, *i.e.*, Manitoba Hydro, in order to at least break even. Clearly Manitoba Hydro could pay less if there was less congestion and, indeed, it could act as its own trader.¹³³ Since, as described above, it can exercise power over its own transmission system, it can limit the amount of congestion that is realised.¹³⁴ It is in this sense that Manitoba Hydro would be exercising the market power it has on the Ontario to Manitoba transmission path: it provides all of the demand for exports that exporters on that intertie face. Thus, facing a vertically integrated external market monopolist should reduce the rate of participation by bidders in the associated FTR auctions.

Second, in other cases—such as Michigan (part of MISO’s marketplace) during the period beginning with market opening in May 2002 and concluding in March 2005—the structure of the external market takes the form of an open-access transmission system without a competitive wholesale market. The absence of a competitive wholesale market means that generation dispatch instructions, including inter-jurisdictional trades cannot be driven by price signals emanating from a spot market. Since the principal economic factor that drives inter-jurisdictional trade of electricity is relative prices, the

¹³² To hedge itself against this uncertainty, the exporter might decide to purchase the relevant FTR.

¹³³ Both Manitoba Hydro and Hydro Quebec have trading units that are active in Ontario’s electricity market.

¹³⁴ This does not mean that the external system operator can exert absolute control over transmission system congestion. For instance, the amount of electricity that can safely be transmitted over a particular transmission line can change with little notice for a variety of technical reasons, *e.g.*, an equipment outage. This can lead to unforeseen congestion that market participants may want to either hedge or try to outright profit from.

lack of a competitive wholesale market is expected to be associated with a less dynamic trading relationship. Consequently, fewer traders are expected to want to hold the associated FTRs, in particular as hedges, thereby reducing the rate of participation by bidders in the associated FTR auctions.

Taken together, it is anticipated that there would be fewer market participants who would want to hold FTRs associated with transmission paths connecting Ontario's electricity system to substantially different neighbouring systems than otherwise. Because it reflects a fundamental economic distinction between market designs, this is the most important explanatory variable under consideration.

3.2. Number of FTRs available

The number of FTRs available for sale in each auction is known in advance of the auction itself. This number is related to the physical capacity of the transmission infrastructure. Since more electricity can flow over transmission lines with greater capacity, a given difference in prices between Ontario and an external market can result in greater electricity flow than feasible with less transmission capacity. Likewise, the greater is the number of transactions that can be accommodated on the path.

Greater electricity flows and/or transaction numbers mean that there are potentially more firms concerned with hedging the uncertainty associated with uncertain congestion. The greater the number of FTRs available for sale is, therefore, expected to increase the rate of participation by bidders in the associated FTR auctions.

3.3. Previously observed congestion

For inter-jurisdictional traders of electricity, the uncertainty associated with congestion is a significant concern as it constitutes an uncertain cost; for financial-only economic agents, congestion represents a potential source of income. This is one of the principle

Figure VII-2: Available FTRs and number of bidders

Table VII-3: Average number of FTRs available at auction

Import Paths	Average # Available	Export Paths	Average # Available
MBSI to ONZN	57	ONZN to MBSI	52
MISI to ONZN	343	ONZN to MISI	392
MNSI to ONZN	42	ONZN to MNSI	63
NYSI to ONZN	525	ONZN to NYSI	469
PQAT to ONZN	155	ONZN to PQAT	284
PQBE to ONZN	167	ONZN to PQDA	72
PQDA to ONZN	48	ONZN to PQHZ	27
PQDZ to ONZN	29		
PQPC to ONZN	67		
PQXY to ONZN	16		

number of bidders.

Table VII-3 reports, on a path-by-path basis, the average number of FTRs available for auction. It is clear that certain paths tend to have many more FTRs available, in particular, the paths to and from Michigan, New York, and Quebec AT.¹³⁸ With respect to those paths connecting Ontario to a neighbour with a competitive wholesale market, the average number of FTRs available is 443. For all other paths, the average is 95.

These results both indicate the importance of including this variable in the model and confirm the expected effect described in section 3, namely that greater numbers of available FTRs will increase the number of bidders in the associated auctions. As well, the results suggest the possible impact of omitting this variable. The data report that the paths with the most FTRs are the paths to and from New York. New York is also the only external market that opened its wholesale market before Ontario. As a result, failing to account for the number of FTRs available at auction is likely to cause the size of the coefficient associated with the market structure dummy variable to be biased upward. In other words, the part of the relatively high number of bidders for New York-related FTRs that is due the relatively large number of FTRs available would be captured by the market structure variable if the number of available FTRs were omitted from the model.

4.4. Previously observed congestion

In section 3 it was stated that the number of bidders that contest a particular FTR auction is expected to be increasing in previously observed congestion. Moreover, two measures of previously observed congestion were proposed (with the second being preferred): the lag of payout and the lag of the proportion of hours in which the

¹³⁸ Recall that the Quebec AT transmission path is relatively new, with only 3 FTR auctions having been held for each direction of the transmission path (Table VII-1).

Figure VII-3: First and second lag of payout and number of bidders¹³⁹

transmission path was congested. Data regarding the first two lags of the former are plotted in Figure VII-3, while data regarding the first two lags of the latter are plotted in Figure VII-4.

Note that the number of observations plotted is 722—the number of auctions in the data set—for both the first and second lags of both the payout and the proportion of hours congested. The reason that observations are not lost as a result of using lags is that both the payout and the proportion of hours congested are physical properties of the

¹³⁹ The loss of observations associated with lagging the data occurs for the same reason as discussed in chapter V. In short, because FTR auctions are not held every month, each lagging operation causes the loss of one observation for each gap.

transmission and are, therefore, observed regardless of whether an FTR auction has been held.

It is clear from Figure VII-3 that neither of the first two lags of FTR payout are statistically meaningful explanatory variables of the number of bidders. In other words, the number of bidders in the auction market does not seem to be related to lagged congestion measured in dollars. It is clear from the figure that there are a number of outlying observations, about 1% of all observations, which may be distorting the relationship between lagged congestion and the number of bidders. The conclusion about the relationship, however, is not altered by either a logarithmic transformation of the lag of payout or the removal of the influential observations.¹⁴⁰ As described in section 3, a positive relationship was expected.

The data plotted in Figure VII-4 suggest a positive relationship between the number of bidders and the first two lags of congestion measured as a proportion of hours in which the relevant path was congested. This is the positive result expected from section 3.

Since the purpose of this variable's inclusion in the model is to control for the role of previously observed congestion in determining the number of economic agents interested in the FTR auction market, the proportional measure of congestion is adopted as the measure of choice. See section 3.3 for a more extensive explanation.

¹⁴⁰ Implementing a logarithmic transformation requires that payouts observed to be zero must be dealt with systematically as the natural logarithm of zero is undefined. A variety of rules could be adopted. First, the observations with a zero payout could be dropped, but this would induce serious bias in any resulting analysis. Second, payouts of zero dollars could be converted to a small number, say \$0.01, so that the natural logarithm could be taken without issue. Third, a dummy variable could be defined for the observations with a zero payout. None of these rules result in a different conclusion being drawn with respect to the relationship between the payout and the number of bidders. These issues are not pursued at length because this particular measure of congestion is not adopted in the analysis reported in this chapter.

Figure VII-4: First and second lag of proportion of hours congested and number of bidders

5. Methodology

This chapter is interested in assessing the population regression function $E[bidders|X]$, where X is a set of explanatory variables. There are a variety of econometric methods available to facilitate this undertaking. The simplest method is use of the OLS estimator taking either the number of bidders or its logarithmic transformation as the dependent variable. This method, including its short-comings in the event that the dependent variable is a non-negative count variable, is discussed in section 5.1. The standard method for modelling count data—the Poisson regression model—including issues regarding its application and the process by which these issues can be dealt with, is discussed in section 5.2. Specification of X is also discussed in this section. Section 5.3

discusses a selection of alternatives to use of the Poisson distribution in the event that the dependent variable is a count variable.

5.1. OLS regression

The simplest method available to model the conditional expectation stated above is as a linear relationship, *i.e.*, $E[bidders|X] = X\beta$. Such a model can easily be estimated by OLS. The parameter estimates can be interpreted in the usual fashion. The important issue here is its applicability to modelling circumstances where the dependent variable is a count variable. Critically, since the number of bidders is definitionally restricted to be a non-negative integer, the conditional expectation of the number of bidders given X should, at the very least, not be negative. Under a presumed linear relationship, however, there is no guarantee that the predicted number of bidders will be non-negative. As a result, application of OLS when the dependent variable is a count variable is conceptually equivalent to application of OLS to other circumstances in which the dependent variable is of a limited dependent nature, *e.g.*, use of the linear probability model with a binary dependent variable. In particular, econometric methods exist that expressly deal with count data.

Before discussing the most widely applied of these—the Poisson regression model—it is worth noting that if the dependent count variable is strictly greater than 0, *i.e.*, has a minimum of 1, a common alternative to is to transform the dependent variable by taking its natural logarithm. The interpretation of the estimated coefficients changes as a result. In particular, it would be said that the dependent variable changes by the coefficient estimate multiplied by 100 percent for a one unit increase in the level of the independent variable, holding all other variables in the model constant. See Wooldridge (2002, p. 645) for additional detail regarding the application of this method. Given the drawbacks associated with these linear methods, the related estimates are not

reported here.

5.2. Poisson regression and parameterisation

The most common econometric framework by which count data models are estimated is the Poisson regression model, estimated by maximum likelihood. The Poisson distribution itself is described first, and is followed by a discussion of how it can be used to parameterise the conditional mean.

5.2.1. Poisson distribution

A random variable Y is Poisson distributed with parameter λ if it takes on integer values $y = 0, 1, 2, 3, \dots$ with probability

$$Pr(Y = y) = \frac{e^{-\lambda} \lambda^y}{y!} \quad (\text{VII-1})$$

where $y!$ is y -factorial and $\lambda > 0$. The first and second moments of the Poisson distribution are

$$E(Y) = \lambda$$

and (VII-2)

$$V(Y) = \lambda$$

respectively. Equation (VII-2) illustrates one of the most important characteristics of the Poisson distribution: the mean and variance are equal, a property referred to as equidispersion. For additional detail, see Cameron and Trivedi (2005, p.668) among many other references. The ability to parameterise λ while also satisfying $\lambda > 0$ is what makes use of the Poisson distribution attractive from an econometric modelling perspective. These issues are discussed in the next section.

5.2.2. Estimation method

The econometric model, specified in the next section, is estimated with the Poisson quasi-maximum likelihood (PQML) estimator described by Wooldridge (1999 and 2002). This estimator is chosen because it generates consistent estimates under the lone assumption that the conditional mean is correctly specified. In particular, the estimator is robust to departures from the equidispersion property associated with the Poisson distribution, equation (VII-2).¹⁴¹ Thus, the conditional distribution of the number of bidders in FTR markets need not be precisely Poisson distributed for the estimator to be applied. Robustness to departures from this property of the Poisson distribution is important because, as reported in Table VII-2, there is some evidence that the number of bidders in FTRs auctions is underdispersed, leading to concerns that the standard errors may be biased.

The data can be weighted on a path-specific basis so as to account for the data being observed in relation to 17 distinct transmission paths. In section 6, estimates are reported both without and with path-specific weighting. When path-specific weights are excluded, the result is that the data are pooled. For the technical process used to derive the PQML estimates with path-specific weights, see Simcoe (2007).¹⁴²

5.2.3. Parameterisation

The conditional probability density function used for the Poisson regression model is given by

$$f(bidders_{it}|X_{it}, path_i) = \frac{e^{-\lambda_{it}} \lambda_{it}^{bidders_{it}}}{bidders_{it}!} \quad (VII-3)$$

¹⁴¹ In fact, the standard errors estimated by the Poisson quasi-maximum likelihood estimator are robust to both underdispersion and overdispersion, both arbitrary heteroskedasticity and autocorrelation, and clustering. See Wooldridge (1999) for additional detail.

¹⁴² Implementation of this method is not a standard feature in Stata 11.

where i indexes the 17 distinct transmission paths under consideration and t indexes the 94 months of the study period. Thus, $bidders_{it}$ is the number of distinct economic agents that contest the auction for FTRs valid for path i and month t , $path_i$ is a dummy variable for path i , and $\mathbf{X}_{it}$ is the set of data regarding explanatory variables other than the path-specific dummy variables (including a full set of time period dummy variables as per Wooldridge (2002, p. 672)). The term λ_{it} is the conditional mean of the number of bidders in the auction for FTRs valid for path i in month t and is assumed to be

$$\lambda_{it} = E[bidders_{it} | \mathbf{X}_{it}, path_i] = path_i * \exp(\mathbf{X}_{it}\boldsymbol{\beta}) \quad (\text{VII-4})$$

where

$$\begin{aligned} \mathbf{X}_{it}\boldsymbol{\beta} = & \beta_0 + \beta_1 market_{it} + \beta_2 available_{it} \\ & + \delta_1 congestion_{i,t-1} + \delta_2 congestion_{i,t-2} + \sum_{t=1}^{t=94} \theta_t month_t \end{aligned} \quad (\text{VII-5})$$

where $market_{it}$ is a dummy variable indicating the nature of the external market associated with path i during month t (equal to 1 if the external jurisdiction has a competitive wholesale market and an open transmission system and 0 otherwise), $available_{it}$ is the number of FTRs available for auction and valid on path i in month t , $congestion_{i,t-j}$ is the j^{th} lag of the congestion measure ($j = 1, 2$), and $month_t$ is a dummy variable for FTRs valid in month t .

These variables, with the exception of the path- and time-effects, are described in greater detail in section 4. With respect to the path- and time-specific effects, inclusion can help to ameliorate concerns regarding possible omitted variable bias. In particular, path-specific weights control for distinct path characteristics such as average transmission path capacity and geographic location. Time-specific effects control for intertemporal characteristics that impact all transmission paths such as introduction of Ontario's programme of generation procurement (and its related wholesale market

impact as described in chapters II, III, and IV), the regional power system problems experienced in the summer of 2003, and macroeconomic cycles.

To allow for the impact of information regarding the FTR market to affect the number of bidders that decide to contest an FTR auction, two lags of the measure of congestion that bidders are anticipated to respond to are included in the model.

Taken together, it is argued that these variables explain a significant portion of the variation of the number of bidders that decide to contest the auction for FTRs valid on path i during month t .

5.2.4. Interpretation of estimates

A few additional points regarding the interpretation of the results related to the Poisson regression model merit mentioning. First, the signs of the reported coefficients can be interpreted in a manner analogous to those related to OLS results: a positive sign indicates that an increase of an independent regressor increases the number of bidders in the relevant FTR auction.

The marginal effect cannot, however, be interpreted analogously. To find the marginal effect of a change of the k^{th} independent regressor, differentiate equation (VII-4) with respect to x_k to get

$$\frac{\partial E[bidders_{it}|X_{it}, path_i]}{\partial x_k} = path_i * \beta_k * \exp(X_{it}\beta) \quad (\text{VII-6})$$

Recall that $path_i$ is the path-specific weight. Clearly the marginal effect is not invariant to the data, X_{it} . Thus, a rule must be adopted in order to report meaningful results. The standard approach is to consider the average change of the number of bidders as the k^{th} independent variable changes. All other things equal, Cameron and Trivedi (2005, p. 669) show that for the Poisson regression model, this effect is $\hat{\beta}_k \overline{bidders}$, where

$\hat{\beta}_k$ is the estimated coefficient and $\overline{bidders}$ is the average number of bidders in FTR auction markets.

One important corollary relates to the interpretation of the relative marginal effects of different regressors. If, say, $\hat{\beta}_1 = 2\hat{\beta}_2$, then all other things equal a particular change in x_1 will have twice the impact on the number of bidders in FTR markets as the same change in x_2 .

An alternative presentation of the estimation results is in the form of incidence-rate ratios (IRR). IRRs are interpreted as the proportional change of the dependent count variable that results from a one-unit change of the associated explanatory variable.¹⁴³ For instance, if the IRR associated with the *market_{it}* dummy variable is, say, 1.1, then the results can be interpreted (assuming the value is statistically significant) as suggesting that the number of bidders that contest FTR auctions associated with competitive external markets is 1.1 times (10% greater than) the number that contest other FTR auctions. In this case, a one-unit change of the variable constitutes the difference between the two possible external market states.

5.3. Alternatives to Poisson regression

Two alternatives to use of the Poisson regression model are discussed in the following sections. They are the negative binomial regression model and the gamma regression model.

5.3.1. Negative binomial regression

A common alternative to the Poisson regression model that appears in the literature, including in a number of the analyses discussed in the literature review, is the negative

¹⁴³ A good discussion of IRRs, including their derivation, is provided in the Stata reference manual, StataCorp (2009).

binomial regression model. Details regarding this regression model are not provided here. Instead, readers are referred to Cameron and Trivedi (2005, p. 675) for details. The reason for omitting this discussion relates to the inapplicability of this model to the data under analysis for all but one purpose.

The first two moments of the negative binomial distribution are

$$E(y|\lambda, \alpha) = \lambda$$

and

(VII-7)

$$V(y|\lambda, \alpha) = \lambda(1 + \alpha\lambda) = \lambda + \alpha\lambda^2$$

respectively. See Cameron and Trivedi (2005, p. 676). Note that $\alpha > 0$ by definition of the distribution. Note as well that $\lambda > 0$ because the mean of a non-negative count variable must be positive as long as the count observations are not all zeros. The definitional restriction of α implies that the variance exceeds the mean. In other words, the negative binomial distribution assumes the underlying data to be overdispersed.

Use of the negative binomial regression model requires that the parameter α from equation (VII-7) be estimated. This parameter can be thought of as a measure of overdispersion since it is the critical link between the distribution's mean and variance. In particular, a relatively large value of α indicates a relatively large degree of overdispersion, while a relatively low value indicates a relatively small degree of overdispersion. Thus, as stated above, the negative binomial regression model cannot accommodate a count variable that is underdispersed. Recall that, as reported in Table VII-2, the number of number of bidders in FTR auctions is slightly underdispersed.

Notwithstanding the apparent underdispersion of the dependent variable, it remains an open question whether this feature of the data can be dealt with by the parameterisation

described in the previous section. Application of the negative binomial regression model to the data set can be used as a test of whether this is the case or not. In particular, if the data are underdispersed then application of the maximum likelihood estimation technique necessary to solve the negative binomial regression model will result in the lowest value of the overdispersion parameter being selected. In other words, the parameter α will converge to zero as the maximum likelihood technique iterates, with convergence ultimately not being achieved. In fact, standard regression packages, such as Stata 11, will report estimates identical to those associated with the Poisson regression model. This is not surprising since the Poisson distribution is the limiting distribution of the negative binomial distribution as $\alpha \rightarrow 0$. See, *e.g.*, Ross (1988), for additional detail regarding the relationship between the Poisson and negative binomial distributions.¹⁴⁴ Such results strongly suggest, at the very least, the absence of overdispersion in the dependent variable.

This is the result found in relation to the number of bidders in Ontario's FTR auction market. As a result, the estimates themselves are not reported.

5.3.2. Gamma regression model

The gamma regression model, despite certain short-comings, is another alternative to the Poisson regression model that is available for use when the dependent variable is both a count variable and underdispersed. Its use in such situations was proposed by Hardin and Hilbe (2001) and Hilbe (2005).

Suppose a random variable y is gamma distributed with parameters α and β . Its density is

¹⁴⁴ As well, the standard chi-square likelihood ratio test of overdispersion ($H_0: \alpha = 0$ against $H_a: \alpha > 0$) that is typically conducted in association with estimation of the negative binomial regression will be reported as a chi square equals 0 with a p-value of 1.000.

$$f(y; \alpha, \beta) = \frac{1}{\Gamma(\alpha) \beta^\alpha} y^{\alpha-1} e^{-y/\beta} \quad (\text{VII-8})$$

where $y > 0$, $\alpha > 0$, $\beta > 0$, and $\Gamma(\alpha) = (\alpha - 1)!$. The expectation (mean) of the gamma distribution is $\alpha\beta$ and the variance is $\alpha\beta^2 = (\alpha\beta)\beta$. The parameter β is a scaling parameter. Note how its value links the mean and the variance together, *i.e.*, the variance is β times the mean.

While the continuous nature of the distribution is a drawback relative to use of the Poisson or negative binomial distributions when the dependent variable is a count, it is able to directly accommodate underdispersed data unlike either of them. This is evident from the representations of the mean and variance above. There is no requirement that the latter be greater than the former, *i.e.*, $0 < \beta < 1$ is permitted. Application of this distribution in a regression context allows for explicit testing for underdispersion or, indeed, overdispersion.

Also, note that in equation (VII-8), $y > 0$. This indicates that the gamma distribution is defined for positive values of y , *i.e.*, undefined for non-positive values of y . This differs from the Poisson distribution, which, in particular, is defined at $y = 0$. In general, use of the gamma distribution can be problematic for count data if the counts are permitted/observed to be zero. However, as noted in section 4.1, all FTR auctions that have been held in Ontario have been contested by at least one bidder, suggesting that this issue is not of great concern in this context.

The mean is parameterised in a manner broadly analogous to use of the Poisson distribution. Underdispersion is accounted for by selection of the scaling parameter, β . Hilbe (2005) provides the programming code necessary to estimate the model in Stata.

6. Empirical results and discussion

6.1. Empirical results

Table VII-4 reports econometric results associated with estimation of the model specified above. Results associated with the pooled Poisson, weighted Poisson, and weighted gamma estimators are reported. Due to underdispersed nature of the number of bidders, results associated with the negative binomial estimator are omitted. In each case, the model is estimated without—specification (1)—and with—specification (2)—the lags of congestion. All specifications include time-specific dummy variables, the coefficients related to which are omitted. The notes associated with the table provide additional detail regarding its contents.

Using the results reported in Table VII-4, marginal effects and incidence-rate ratios (IRR, for the market variable only) are constructed for each combination of specification and estimation technique. These are reported in Table VII-5. The notes associated with the table for additional detail regarding its contents.

All estimation results were generated using Stata 11.

Table VII-4: Econometric estimation results

	Pooled Poisson		Pooled Gamma		Weighted Poisson		Weighted Gamma	
Variable	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)
Market	0.183 (0.039)****	0.164 (0.039)****	0.171 (0.036)****	0.157 (0.036)****	0.147 (0.072)**	0.148 (0.072)****	0.145 (0.053)****	0.143 (0.053)****
Available	0.715 (0.077)****	0.724 (0.075)****	0.764 (0.068)****	0.766 (0.068)****	0.639 (0.094)****	0.639 (0.098)****	0.692 (0.080)****	0.687 (0.080)****
L1.Congestion	—	-0.379 (0.289)	—	-0.275 (0.255)	—	-0.555 (0.362)	—	-0.424 (0.242)*
L2.Congestion	—	0.797 (0.304)****	—	0.578 (0.245)***	—	0.535 (0.281)*	—	0.293 (0.232)
Constant	0.699 (0.096)****	0.694 (0.095)****	1.226 (0.285)****	1.225 (0.283)****	1.063 (0.095)****	1.048 (0.097)****	1.589 (0.310)****	1.589 (0.310)****
Dispersion	—	—	0.081 (0.004)****	0.080 (0.004)****	—	—	0.069 (0.004)****	0.068 (0.004)****
log(L)	-1115.2	-1113.6	-809.0	-805.8	-1047.8	-1047.1	-748.9	-747.4
Wald chi-square	339.6 (0.0000)	365.6 (0.0000)	420.6 (0.0000)	430.8 (0.0000)	160.7 (0.0000)	161.5 (0.0000)	83.2 (0.0000)	86.8 (0.0000)
Pearson GOF	170.4 (1.0000)	166.4 (1.0000)	172.0 (1.0000)	168.4 (1.0000)	140.3 (1.0000)	138.7 (1.0000)	142.5 (1.0000)	141.2 (1.0000)
AIC	2414.5	2415.2	1804.1	1801.7	2417.9	2420.4	1715.9	1716.8
N	722	722	722	722	722	722	722	722

Notes: Coefficient estimates related to each model are reported in the table, not marginal effects or incidence-rate ratios.

The available and congestion variables are measured in thousands of units and thousands of dollars, respectively.

Standard errors are in parentheses: robust for the pooled Poisson model and PQML (Wooldridge, 1999) for the weighted Poisson model. Time period dummy variables are included in each specification but are excluded from the results. “—” indicates that a variable/value is not included in/relevant to the appropriate specification. The dispersion parameter related to the gamma model and is reported with its standard error. The reported test of significance is of the null

hypothesis that the dispersion parameter equal unity against the general alternative. The Wald chi-square statistic, reported with its associated p-value, test the joint significance of the explanatory variables described. Pearson GOF is the Pearson chi-square goodness-of-fit test statistic. Estimates from the negative binomial model are omitted: underdispersion implies that they are the same as those from the Poisson model. Asterisks indicate the level of significance: * 10%, ** 5%, *** 1%, and **** 0.1%.

Table VII-5: Marginal effects and incidence-rate ratios

Variable	Pooled Poisson		Pooled Gamma		Weighted Poisson		Weighted Gamma	
	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)
<i>Marginal effects</i>								
Market	0.490****	0.440****	0.458****	0.421****	0.392**	0.393****	0.386****	0.380****
Available	1.916****	1.940****	2.048****	2.053****	1.700****	1.670****	1.840****	1.827****
L1.Congestion	—	-1.016‡	—	-0.737‡	—	-1.476‡	—	-1.128*
L2.Congestion	—	2.134****	—	1.549***	—	1.423*	—	0.779‡
<i>Incidence-rate ratios</i>								
Market	1.201****	1.179****	1.187****	1.170****	1.158**	1.159****	1.156****	1.154****

Notes: Results are based on Table VII-4. The available and congestion variables are measured in thousands of units and thousands of dollars, respectively. Standard errors are omitted, but significance is exactly the same as in Table VII-4. Levels of statistical significance are repeated for emphasis and are unchanged from Table VII-4. In the case of IRRs, the reported test of significance is of the null hypothesis that the reported coefficient estimate equals unity against the general alternative. “—” indicates that a variable/value is not included in/relevant to the appropriate specification. Asterisks indicate the level of significance: * 10%, ** 5%, *** 1%, and **** 0.1%. Also, ‡ indicates the absence of statistical significance at the 10% level.

6.2. Discussion

Given its ability to explicitly model count data, the results associated with the Poisson model are considered first. With pooled data, in specification (1) where the lags of congestion are omitted, the variables that control for the nature of the external market (called “Market” in the results tables) and the number of FTRs available at auction (called “Available” in the results tables) both have the anticipated sign and are statistically significant. In particular, the marginal effects associated with the two variables are approximately 0.49 and 1.92, respectively. These results imply that there are, on average, 0.49 more bidders in FTR auction markets where the right being auctioned is associated with an external market that is competitive in nature than otherwise. Thus, there are approximately 0.49 more bidders on the paths to and from New York (since Ontario’s market opening in 2002) and Michigan and Minnesota (since market opening there in 2005). Alternatively, these results can be interpreted as incidence-rate ratios. Such an interpretation would imply that there are, on average, approximately 20% more bidders in FTR auction markets where the right being auctioned is associated with an external market that is competitive in nature than otherwise. With respect to the number of FTRs available, the results imply that there are, on average, 1.92 more bidders for every 1000 unit increase of the number of rights available at auction. As stated above, both of these results are statistically significant.

Augmenting specification (1) with two lags of congestion, *i.e.*, the proportion of hours in which the transmission line was congested, is the definition of specification (2).

Continuing with pooled data, the results regarding the nature of the external market and the number of FTR available are similar compared to specification (1). In particular, the marginal effects associated with the market variable and the number of FTRs available at auction are approximately 0.44 and 1.94, respectively. Both estimates have the anticipated sign and are statistically significant. With respect to the lags of

congestion, the estimated marginal effects associated with the first and second lags are approximately -1.02 and 2.13, respectively. The sign of the first lag is contrary to that anticipated by the preceding discussion. However, this result is not statistically significant (even at a 90% level of confidence). The sign of the second lag is as anticipated in the preceding discussion but is also statistically significant. The estimate implies that an increase in the fraction of hours in which a transmission line is congested by, say, 0.01 (approximately 7 hours in a month) increases the number of bidders in the related FTR auction by approximately 0.02 two months later.

While these results are somewhat mixed, they suggest the possibility that lags of congestion are meaningful explanatory variables of the number of bidders in FTR auction markets, but with an impact delayed by more than a single month.

The Poisson specification can also be assessed for its goodness-of-fit. In particular, the Pearson chi-square test can be implemented. For specifications (1) and (2), the test-statistic values (p-values) are approximately 170.4 (1.000) and 166.4 (1.000), respectively. A statistically significant result would imply that the particular specification in question is not appropriate (without providing explicit information as to why), perhaps due to functional form, omitted variables, or a data dispersion issue. The results reported here indicate that use of the Poisson regression model is not overly problematic with respect to analysing the number of bidders in FTR auction markets with either set of regressors.

While the AIC criterion suggests a preference for specification (1) over specification (2), the results associated with the lags of congestion, as well as the underlying theoretical justification for their inclusion, suggest a preference for specification (2). In any event, the estimates associated with the market variable (the variable of greatest interest) and the number of FTRs available at auction are similar under each specification.

While not reported in Tables VII-4 and VII-5, the negative binomial regression model was also used to estimate each of the specifications discussed above in relation to the Poisson regression model. The results of these undertakings yielded an overdispersion parameter that regularly converged to zero. As described above, the Poisson distribution is the limiting distribution of the negative binomial distribution as the overdispersion parameter goes to zero. These results confirm the previous finding that the data are not overdispersed and do not become overdispersed as a result of parameterising the mean function. While underdispersion is not necessarily implied by this finding, *i.e.*, the data could still be equidispersed, the possibility is not foreclosed.

The gamma regression model allows for underdispersion to be accounted for explicitly. Results associated with this model are also included in Tables VII-4 and VII-5. With pooled data, the marginal effects associated with the market variable and the number of FTRs available at auction are approximately 0.46 and 2.05, respectively, for specification (1) and 0.42 and 2.05, respectively, for specification (2). Each estimate is similar in magnitude to that associated with the Poisson model and is similarly statistically significant. With regard to specification (2), the marginal effect associated with the first lag of congestion is negative, contrary to expectations, but not statistically significant. The marginal effect associated with the second lag is approximately 1.55 (compared to 2.05 under the Poisson model) and is statistically significant.

Taken together, these results are similar to those associated with the Poisson model. However, note that the dispersion parameter reported in Table VII-4 is statistically less than one.¹⁴⁵ Notwithstanding the similarity of coefficient estimates, this suggests a preference for use of the gamma regression model in considering the number of bidders

¹⁴⁵ The reported tests of statistical significance generally test the null hypothesis that the associated coefficient is zero against the general alternative. As described in the notes associated with Tables VII-4 and VII-5, exceptions are associated with the dispersion parameter and the IRRs where the null hypotheses are that the associated coefficient is *one* against the general alternative.

in FTR markets, though this must be weighed against the drawbacks identified in relation to the gamma model.

Gamma and Poisson regression yield largely similar empirical results. This result lends confidence to the robustness of the results and suggests that the underdispersed nature of the number of bidders, while not being ideal for use of Poisson regression, is not significant enough to seriously bias the Poisson results.

Tables VII-4 and VII-5 also report estimates associated with weighted Poisson and gamma regression models. With respect to the market variable, the estimated marginal effects range from approximately 0.38 to 0.39, all of which are statistically significant. This result suggests that there are approximately 0.4 more bidders in FTR auction markets where the right being auctioned is associated with an external market that is competitive in nature than otherwise. Relatedly, the incidence-rate ratios range from 1.154 to 1.159, suggesting that there are approximately one-sixth more bidders in FTR auction markets where the right being auctioned is associated with an external market that is competitive in nature than otherwise. With respect to the number of FTRs available at auction, the estimated marginal effects range from approximately 1.67 to 1.84, all of which are statistically significant. This result suggests that there are approximately 1.75 more bidders in FTR auction markets for every 1000 additional FTRs available for sale. None of the coefficients associated with the lags of congestion are statistically significant.

The results suggest a number of findings. First, the nature of external markets is an important factor in the determination of the number of bidders that contest FTR auction markets. In particular, the evidence reported above suggests that there are more bidders where the transmission path associated with the FTR connects Ontario's electricity system to a neighbouring jurisdiction with a competitive wholesale market

than otherwise. This confirms the theoretical expectation described above. Second, there are more bidders in FTR auctions where there are more FTRs available for auction. This also confirms the theoretical expectations described above. Third, there is moderate evidence that the number of bidders in FTR auction markets is meaningfully explained by previous observations of congestion. While the theoretical argument stated above argued that a positive relationship should be anticipated, support is not found uniformly across all specifications and modelling approaches. Fourth, the number of bidders is underdispersed and the underdispersion is not eliminated by parameterisation of the mean. Fifth, notwithstanding the apparent underdispersion of the number of bidders, application of a modelling approach that explicitly accounts for this characteristic of the data does not yield meaningfully different results, thereby suggesting that the practical effect of underdispersion is itself not overly meaningful.

7. Conclusions

This chapter undertakes an analysis of the number of economic agents that decide to contest auctions for FTRs in Ontario. Each FTR is valid on a particular transmission path connecting Ontario to a neighbouring jurisdiction for a specified period of time. Due to the overlapping nature of long-term FTRs, attention is paid to short-term FTRs alone. The panel of data consists of observations on 17 transmission paths over the period June 2002 to March 2010 and is unbalanced as a result of auctions not being held in relation to every path each month.

The number of bidders is, by definition, a non-negative count variable that is observed to always be strictly positive. Preliminary evidence suggests that this variable is underdispersed, *i.e.*, its mean is greater than its variance. Econometric techniques appropriate to this type of data are considered, in particular, the Poisson regression model, the negative binomial regression model, and the gamma regression model.

The number of bidders is expected to vary across auctions based on the characteristics of the underlying transmission path. A critical characteristic that influences the number of bidders is the nature of the relevant external jurisdiction. In particular, it is argued that FTRs associated with transmission paths that connect Ontario to jurisdictions that operate competitive wholesale electricity markets will be more heavily contested at auction than other FTRs. Evidence in support of this argument is found which indicates that the average number of bidders is approximately one-sixth higher when the external wholesale electricity market is competitive in nature. This result is statistically significant and suggests that such FTR auctions are indeed more heavily contested.

This finding indicates that, as expected, behaviour of economic agents in the FTR auction market is related to structure of the underlying electricity market. Thus, transmission lines that link jurisdictions with competitive wholesale markets, whose physical capacity is therefore more contestable, are associated with FTR auction markets that are themselves for heavily contested. In other words, less regulated markets attract larger numbers of bidders than more regulated markets as there are both greater needs for the security associated with hedging and greater opportunities for profit to be made.

The influences of other characteristics are also considered. In particular, it is found that the number of bidders is increasing in the number of FTRs available at auction. However, the impact of previously observed congestion on the number of bidders, which was initially expected to be positive, is found to have some qualified support.

A number of possibilities for future research present themselves, one of which is discussed here. The number of bidders that contest an auction market could be useful both in modelling the auction market clearing price and in assessing the value of the auction market clearing price as a forecast of congestion, *i.e.*, the forward market unbiasedness hypothesis. Assessment of this relationship was the principle purpose of

chapters V and VI. For instance, it may be the case that lightly contested auctions, say, two bidders or less, lead to relatively low auction market clearing prices. This would suggest a bias that could be accounted for in the assessment of the forward market unbiasedness hypothesis. (This analysis was not included in chapters V and VI because, due to data confidentiality issues, information regarding the number of bidders is not available for all FTR auctions that have been observed since market opening.)

Chapter VIII: Conclusion

A competitive wholesale electricity market began operation in Ontario in May 2002. This purpose of this thesis is to undertake an assessment of certain aspects of this market. The aspects of the market to which special attention is paid are (1) issues regarding cost allocation related to implementing certain government policies and (2) the performance of financial transmission rights markets. This assessment is intended to contribute to the broader understanding of electricity market design and operation.

Chapter II formulated an analytical model of Ontario's electricity market for use in counterfactual policy analysis. To that end, a six-equation model of the wholesale electricity market was developed and used to construct a base case equilibrium. This construction is a crucial component to the process of counterfactual policy analysis as the impact of any counterfactual policy under consideration is defined as the deviation of the resulting (counterfactual) equilibrium from the base case. This was necessary so as to isolate the impact of the alternative policy being considered from errors in modelling historical data.

Chapter III reported a formal analysis of the social cost of CO₂-emission abatement under Ontario's programme of renewable energy generation capacity procurement. The reported results made clear the inadequacy of focusing on the effect of the programme on consumers alone. This necessitated the use of model of the market of the type introduced in chapter II. The analysis concluded that the cost of CO₂-emission abatement under Ontario's programme is well in excess of the cost of CO₂-emission abatement in other jurisdictions and industries. This indicates that the same CO₂-emission abatement achieved in Ontario could have been achieved at substantially lower cost—or substantially greater CO₂-emission abatement could have been achieved at the same cost—under alternative policy constructs that exist elsewhere.

Based on the results reported in chapters II and III, it was argued in chapter IV that the regulator's procurement policy, which acted in the market by increasing the amount of supply available at each price, was at least partially responsible for the decline of the wholesale market clearing price observed throughout the study period. This shifted costs guaranteed by the regulator from being covered by wholesale market revenue to being covered by the regulator and recovered from consumers through the GA. These increased GA costs led to a general increase in the level of the GA rate charged to Ontario-based consumers who, under current policy, pay all GA-related costs.

At the time of its introduction, the GA rate did not constitute a consistently positive and large proportion of the all-in price. However, the growing importance over time of the GA rate as a component of the all-in price of electricity can be interpreted as a shift away from incremental cost pricing towards average cost pricing, an outcome which has negative implications for the allocative efficiency of the wholesale market. This development also magnifies the importance of the rule used by the regulator to allocate its costs among consumers.

The purpose of chapter IV was to consider whether the current practice of not allocating any of the cost of the regulator's activities—including its programme of generation procurement—to exports was optimal or not. To that end, a set of cost allocation rules that could be used to allocate these costs differently were considered as counterfactual policies in the context of the market model introduced in chapter II. The results of the analysis indicated that an export allocation rate of 32% would be optimal. The results also indicate that the current policy of exempting exports from GA is preferable on total surplus-maximisation grounds than either pro rata application of GA to exports or the adoption of a rule that maximises the surplus of Ontario-based consumers alone.

Chapters V and VI reported the results of a statistical and econometric analysis of the informational efficiency and forward market unbiasedness characteristics of Ontario's short-term (ST) financial transmission rights (FTRs) auction market. FTRs are financial assets that entitle their holder to receive payments proportional to the degree of congestion realised on the relevant transmission path (including the relevant direction). FTRs exist for all transmission paths connecting Ontario with its five neighbouring jurisdictions—New York, Michigan, Minnesota, Manitoba, and Quebec—and are individually valid for one of two durations—one month or one year.

The principal issue related to ST FTRs was the left-censoring of payout at \$0, while the principal issue related to LT FTRs was the overlapping nature of the basic data set. Both issues were dealt with explicitly in chapters V and VI, respectively.

Analysis of the ST FTR market involved narrowing the focus to the four transmission paths connecting Ontario to and from New York and Michigan. The correlation coefficient between the MCP and payout suggested there was no systematic relationship between the two for the New York to Ontario transmission path, a result confirmed by formal econometric analysis. Significantly positive correlations were found in relation to the other three paths, for which formal econometric analysis confirmed a positive relationship between the MCP and payout, though not generally in a one-to-one fashion. As a result, it was concluded that standard joint informational efficiency hypothesis should be rejected. Similar results were obtained by use of various estimators in a panel data context.

Regardless of the approach, it was concluded that while FTR market performance varied across the transmission paths considered and that some performed better than others, the market as a whole was not informationally efficient in the sense that the

MCP for a particular auction does not tend to provide an unbiased forecast of future payout/congestion.

Analysis of the LT FTR market involved 15 distinct transmission paths connecting Ontario with its neighbours. While formal econometric analysis failed to reject the joint informational efficiency hypothesis, large standard errors also resulted in the inability to conclude there was a non-zero relationship between the MCP and payout, thereby undermining the above-stated conclusion.

Chapter VII reported an analysis of the number of economic agents that decided to contest auctions for FTRs in Ontario. Due to the overlapping nature of long-term FTRs, attention was paid to short-term FTRs alone. The number of bidders was, by definition, a non-negative count variable that was observed to always be strictly positive.

Preliminary analysis suggested that this variable was underdispersed. Econometric techniques appropriate to this type of data were considered, the Poisson, negative binomial, and gamma regression models in particular.

The number of bidders was expected to vary across auctions based on the characteristics of the underlying transmission path. A critical characteristic that influences the number of bidders is the nature of the relevant external jurisdiction. Evidence in support of this argument was found which indicated that the average number of bidders was approximately one-sixth higher when the external wholesale electricity market was competitive in nature. Thus, transmission lines that link jurisdictions with competitive wholesale markets were associated with FTR auction markets that were themselves highly contested relative to others.

Consideration of all results together reveals an electricity market in Ontario characterised by a number of inefficiencies. The type of efficiency assessed is not of the usual type, such as dispatch/productive efficiency – regarding which interested readers

might consider consulting the various reports of the Market Surveillance Panel (cited and otherwise). Instead, aspects of capacity investment efficiency and the allocation of resources related to transmission system congestion are assessed.

With respect to capacity investment, the analysis suggests that there are significant inefficiencies associated with Ontario's programme of generation procurement. These inefficiencies manifest themselves in the form of the province paying a premium for renewable energy generation capacity that far exceeds the level necessary to achieve comparable environmental objectives in other markets. The result is that, among other things, (1) consumer prices for electricity are higher than their efficient level, (2) government-owned generation assets, in particular Ontario Power Generation, receive much less revenue and profit than their efficient level, thereby depriving Ontario's provincial government of economic resources that could be expended for alternative purposes, (3) exports are inefficiently high, and (4) all of these effects are growing through time.

With respect to Ontario's market for financial transmission rights, the analysis suggests that auction markets lack informational efficiency in the sense that auction prices are systematically less than payouts. Compared to an informationally efficient state where auction prices approximate payouts, the result is that consumers are worse off since they are the ultimate recipients of incremental auction market revenue.

While the implications of past policy choices are unavoidable, future outcomes could be improved with policy changes, two which are considered here. First, the effect of the renewable energy generation programme in the future would be lessened if the amount of generation subject to its terms ceased growing. Comparable environmental objectives could be achieved in other sectors of the economy, with surplus economic resources remaining for other objectives, including, perhaps most importantly,

significant *additional* carbon dioxide abatement. Second, alternative financial transmission market designs, such as ones that limit total payouts to total congestion rents, thereby reserving all auction market revenue for consumers, should be investigated to determine whether similar outcomes could be achieved with greater benefits for consumers.

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Appendices

Appendix II-A: Global adjustment reform of 2010

From its introduction on 1 January 2005 to 31 December 2010, inclusive, aggregate global adjustment was allocated to consumers as prescribed by Ontario Regulation 429/04. In short, during this time period the allocation rule was such that all Ontario-based consumers paid exactly the same rate in dollars per MWh. Exports were exempt from contributing to global adjustment costs. This rule was described in the main text.

Effective 1 January 2011, as per Ontario Regulation 398/10, the global adjustment allocation rule was changed. The new regulation distinguishes between two classes of consumers: A and B. Class A consumers are defined to be those Ontario-based consumers whose own monthly maximum hourly demand for electricity exceeds, on average, 5 MW during a predefined base period. For instance, in the case of the billing period¹⁴⁶ from 1 January 2011 to 30 June 2011, the base period used to distinguish class A consumers was 1 May 2010 to 31 October 2010, *i.e.*, class A consumers are those whose maximum hourly demand for electricity in May, June, July, August, September, and October 2010 exceeded 5 MW on average.^{147, 148} All Ontario-based consumers who are not members of class A are defined to be members of class B.¹⁴⁹ Consumers always

¹⁴⁶ The billing period is the period in which electricity is consumed.

¹⁴⁷ It is necessary but not sufficient that maximum hourly demand exceed 5 MW in at least one month of the base period for a consumer to be defined as being a member of class A. It is sufficient but not necessary that maximum hourly demand exceed 5 MW in all months of the base period for a consumer to be defined as being a member of class A. There are no restrictions or conditions regarding when in the relevant month the maximum hourly demand for electricity is observed nor how maximum consumption relates to average consumption.

¹⁴⁸ Effective with the billing period beginning 1 July 2011, a billing period from 1 July of Year Y to 30 June of Year Y+1 corresponds to a base period from 1 May of Year Y-1 to 30 April of Year Y. Class A consumers must re-qualify as such on an annual basis.

¹⁴⁹ For the billing period 1 January 2011 to 30 June 2012, Ontario-based consumers who meet the standard required to be members of class A may nonetheless opt to be treated as members of class B.

know in advance of their consumption choices to which class they belong.

Class A consumers are charged global adjustment based on coincident peak demand. This allocation mechanism is referred to as the coincident peak rule. Regarding this allocation mechanism, the IESO states

“[c]oincident peak means that [each consumer’s total global adjustment] costs are calculated based on the percentage that each customer’s demand contributes to overall provincial demand during the five peak hours of a base period. The peak hours are the five hours (occurring on different days) in which the greatest number of megawatts of electricity was used in Ontario” (IESO, undated, p.1).

Class B consumers will continue to be charged global adjustment in proportion to their total monthly consumption, *i.e.*, they continue to pay a global adjustment rate determined as the aggregate global adjustment expenses divided by aggregate Ontario-based demand as implied by equation (II-5).

Notwithstanding the potential significance of this policy change on consumer behaviour, the coincident peak allocation rule applied to class A consumers is ignored in the analysis undertaken in this chapter. There are several reasons for this choice.

First, the time period under study in this chapter ends in June 2011, meaning that at most six out of 109 observations may be affected by the policy change. Associated with a policy change of this type is a learning and adjustment process that has just begun.

Second, Ontario Regulation 398/10 was filed on 22 October 2010. Prior to its publication, the government’s commitment to the particular details contained within the regulation, as well as the timing of publication itself, were not known with certainty. Given that the base period that determined which consumers were members of class A during the final six months (observations) of the data set covered the period from, as

stated above, 1 May 2010 to 31 October 2010 it is unlikely that class A contains many consumers whose maximum hourly consumption in a month would not have exceeded 5 MW on average, *i.e.*, the policy is unlikely to have altered the composition of class A. However, strategic behaviour in relation to this policy change is likely to become a significant issue subsequent to 30 June 2011.

Appendix II-B: Structure of global adjustment expenses

There is a number of different aspects of the regulator's activities that contribute to costs that must be recovered through the GA mechanism. The process accounts for payments arising in relation to: (i) wind generation contracts; (ii) solar generation contracts; (iii) NUGs; (iv) nuclear facilities; (v) baseload hydro; (vi) natural gas capacity contracts; (vii) contingency payments to certain OPG-owned fossil generators; and (viii) OPA conservation programs. There may be particular exceptions to the structure of regulatory intervention described below. The typical case is considered.

After describing the contribution mechanism associated with each of the eight activities of the regulator, the regulator's GA expense equation is written out.

Wind generation

Wind generation contracts specify a fixed price per unit of output for which wind-generated electricity is paid. Such contracts were labelled fixed-price contracts in the main body of the chapter. It is assumed that the fixed price is \$135/MWh. The nature of out-of-market top-up payments is such these generators receive the wholesale market clearing price for their output from the wholesale market and are subsequently paid the difference between the contract price (assumed to be \$135/MWh) and that price. If the wholesale market clearing price were sufficiently high—above \$135/MWh—then the top-up would be negative.

The aggregate amount of wind-fuelled electricity injected into the IESO-controlled transmission grid is observed on an hourly basis. These hourly data are averaged across the hours of the relevant month to generate the data used in this analysis. These data exclude the output of wind generators not connected to the IESO-controlled transmission grid, that is, those generators embedded in the distribution systems of

local distribution companies. As such generation constitutes a small component of aggregate wind generation in Ontario, these facilities are ignored.

Solar generation

Like wind generation contracts, solar generation contracts specify a fixed price per unit of output for which solar-generated electricity is paid. These are fixed price contracts. It is assumed that the fixed price is \$420/MWh. The nature of the top-up payments associated with these contracts is analogous to wind generation contracts.

Solar-fuelled electricity production is not publically available. However, data regarding the level of aggregate capacity of solar installations within Ontario is available. These data are reported in “A Progress Report on Electricity Supply,” published on a quarterly basis by the OPA. For simplicity, it is assumed the production of electricity from solar generators is characterised by a fixed, 10% capacity factor.¹⁵⁰

Non-utility generators (NUGs)

Most NUGs are cogeneration facilities that produce electricity and are integrated into the production process of a non-electricity good. It is assumed that there is 1577 MW of NUG capacity that generates an average of \$75/MWh in capacity and energy payments.

These assumptions may seem unreasonable, but even with them the simulated amount of out-of-market payments received by NUGs (and certain contingency payments, as discussed below) is less than the observed payments to NUGs. The mechanism can be thought of as being equivalent to the one that provides capacity payments to natural

¹⁵⁰ The mechanism described may overstate the out-of-market top-up payments made to solar generators since such output is positively correlated with the hourly wholesale market price. This is because solar generators produce their output during day-time hours due to the availability of the sun, which corresponds to the periods of greater demand and higher wholesale market clearing prices. Given the magnitude of the fixed price guaranteed to generators, this issue is likely to be of minor importance.

gas generators (as described below).

Nuclear facilities

All nuclear-powered generation facilities in Ontario are owned by Ontario Power Generation (OPG). The reactors located in Bruce County are operated under a long-term lease by Bruce Power, a private-sector firm.

It is assumed that this generation earns a fixed price of \$55/MWh. This is a significant simplification: some generation is paid less, some more. The Bruce B generating facility is subject to a price floor under its average unit price. The nature of the top-up payments—which are often negative—is analogous to those under wind and solar generation contracts as described above.

Nuclear-powered generation data are available on a monthly basis from a number of sources, including the periodic reports of the Ontario Energy Board's (OEB) Market Surveillance Panel (MSP) and the Independent Electricity System Operator (IESO).

Baseload hydro

OPG owns and operates the hydroelectric stations that produce electricity on the Niagara and St. Lawrence Rivers. It is assumed that the first 1900 MWh of hydro production in the average hour are paid \$33/MWh. Wholesale market clearing prices in excess of this level result in OPG making contributions to the GA, while prices below this level result in OPG receiving payments from the GA. Output in excess of 1900 MWh earns the wholesale market clearing price and is assumed not to be subject to additional out-of-market top-up or claw-back payments, and is ignored in the calculation of regulator expenses recovered by the GA.

Nuclear-powered generation data are available on a monthly basis from a number of

sources, including the periodic reports of the Ontario Energy Board's (OEB) Market Surveillance Panel (MSP) and the Independent Electricity System Operator (IESO).

Natural gas capacity contracts

The regulator's programme of generation capacity procurement has, as of July 2011, induced the entry of more than 5000 MW of natural gas-fuelled generation capacity. Capacity payments, subject to certain claw-backs described below, are made to these generators.

Data regarding the commissioning of contracted natural gas capacity are reported in "A Progress Report on Electricity Supply," published by the OPA. While this publication is released on a quarterly basis, it reports the formal date of commissioning of contracted natural gas generators. It is assumed that capacity support payments begin at that time. Thus, the amount of natural gas capacity is known on a monthly basis. It is also assumed that contracted capacity is paid an average of \$7,900/MW-month. These contracts generally contain provisions under which the regulator takes back a portion of these capacity costs if the wholesale market electricity price exceeds a contractually-specified incremental cost of production, whereby the generator is deemed to have earned so-called net revenue—revenue in excess of incremental cost—in the wholesale market.¹⁵¹

Certain contingency payments

As a result of the regulator's programme of generation procurement, as well as due to

¹⁵¹ Certain other contractual requirements must also be met. For instance, the wholesale market price must exceed the contractually specified incremental cost for a minimum duration for a facility to be deemed to have started. The contractually specified incremental cost, which includes a component related to operations and maintenance as well as a fuel component, may or may not correspond to a particular facility's physical incremental cost. The basic principle is that the specified value of this term is beyond the control of the generator itself (after the contract with the regulator has been signed).

direct instruction from the provincial government, the fossil energy fuelled generators operated by OPG do not earn sufficient revenue in the wholesale electricity market to cover their variable costs. In order to prevent exit, out-of-market contingency support payments to OPG began in the first quarter of 2009.¹⁵²

Quarterly data regarding the cost incurred as a result of this programme are available in the quarterly financial statements of OPG. The data are converted to a monthly frequency by dividing the quarterly data by 3.

Conservation programs

Aside from its program of generation procurement, the OPA has established a significant number of electricity conservation programs. The cost of these programs is recovered through the GA. Since these programs do not generate revenue in the wholesale electricity market the expenditures on them cannot be thought of as out-of-market top-up payments. Instead, such costs are viewed as constituting a fixed cost borne by the regulator.

Annual data regarding conservation spending are available for the years 2008, 2009, and 2010 in the annual reports of the OPA. To convert these data to a monthly frequency, annual data is divided by 12. Conservation spending before 2008 is ignored (and assumed to be zero), while spending for 2011 is forecast to have grown at the average growth rate of conservation spending over the year 2008 to 2009 and 2009 to 2010, with monthly data being one-twelfth of the 2011 forecast.

Expense equation

The sections above describe the mechanisms by which the eight activities of the

¹⁵² Exit would be an undesirable outcome in the short term since the generators in question provide useful, at times necessary, support for the reliability of Ontario's electricity market.

regulator contribute to GA expenses. These can be written as a single equation as

$$\begin{aligned}
 Exp_t = & q_t^{wind} * (p_c^{wind} - P_t) + q_t^{solar} * solar_{capacity} * (p_c^{solar} - P_t) \\
 & + q_t^{nugs} * (p_c^{nugs} - P_t) + q_t^{nuclear} * (p_c^{nuclear} - P_t) + q_t^{base_hydro} * (p_c^{base_hydro} - P_t) \\
 & + nat_gas_capacity_t + contingency_t + conservation_t
 \end{aligned} \tag{II-6}$$

where all data are converted to hourly averages. With the values that are fixed throughout the period of analysis substituted into equation (II-6), then

$$\begin{aligned}
 Exp_t = & q_t^{wind} * (135 - P_t) + q_t^{solar} * 0.19 * (420 - P_t) \\
 & + 1577 * (75 - P_t) + q_t^{nuclear} * (55 - P_t) + 1900 * (33 - P_t) \\
 & + nat_gas_capacity_t + contingency_t + conservation_t
 \end{aligned} \tag{II-7}$$

Appendix II-C: Solution to the model

The purpose of this appendix is to describe the process used to solve for the base case discussed in-text. The model of Ontario's electricity market is composed of six equations with six endogenous variables and is discussed in detail in-text. The four estimable equations relate to Ontario-based supply, imports, Ontario-based demand, and exports, *i.e.*,

$$q_t^s = \gamma_0 + \gamma_1 p_t + \gamma_2 fuel_t + \gamma_3 baseload_t + \varepsilon_{1t} \quad (II-1)$$

$$q_t^i = \delta_0 + \delta_1 p_t + \delta_2 NY_L_t + \delta_3 linked_t + \varepsilon_{2t} \quad (II-2)$$

$$q_t^d = \alpha_0 + \alpha_1 (p_t + g_t) + \alpha_2 HDD_t + \alpha_3 CDD_t + \alpha_4 M_{t-1} + \varepsilon_{3t} \quad (II-3)$$

$$q_t^e = \beta_0 + \beta_1 p_t + \beta_2 NY_L_t + \beta_3 linked_t + \varepsilon_{4t} \quad (II-4)$$

The fifth equation is the regulator's budget constraint, *i.e.*,

$$\begin{aligned} g_t * q_t^d &= q_t^{wind} * (p_c^{wind} - P_t) + q_t^{solar} * solar_capacity * (p_c^{solar} - P_t) \\ &+ q_t^{nugs} * (p_c^{nugs} - P_t) + q_t^{nuclear} * (p_c^{nuclear} - P_t) \\ &+ q_t^{base_hydro} * (p_c^{base_hydro} - P_t) \\ &+ nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (II-8)$$

The sixth equation is a quantity equilibrium condition, *i.e.*,

$$q_t^d + q_t^e = (1 - losses) * (q_t^s + q_t^i) \quad (II-9)$$

The solution to this system determines equilibrium Ontario-based supply, imports, Ontario-based demand, imports, the wholesale market clearing price, and the GA rate.

Once equations (II-1), (II-2), (II-3), and (II-4) have been estimated, fitted equations for

Ontario-based supply, imports, Ontario-based demand, and exports, can, as discussed in-text, be written as follows

$$\hat{q}_t^s = \hat{\gamma}_{0t} + \hat{\gamma}_1 p_t \quad (\text{II-14})$$

$$\hat{q}_t^i = \hat{\delta}_{0t} + \hat{\delta}_1 p_t \quad (\text{II-17})$$

$$\hat{q}_t^d = \hat{\alpha}_{0t} + \hat{\alpha}_1 (p_t + g_t) \quad (\text{II-21})$$

$$\hat{q}_t^e = \hat{\beta}_{0t} + \hat{\beta}_1 p_t \quad (\text{II-24})$$

The quantity equilibrium condition, equation (II-9), can be re-written using the fitted variables as

$$\hat{q}_t^d + \hat{q}_t^e = (1 - L) * (\hat{q}_t^s + \hat{q}_t^i) \quad (\text{II-C-1})$$

Substitution of equations (II-14), (II-17), (II-21), and (II-24) into equation (II-C-1) yields

$$p_t = a_t - b_t g_t \quad (\text{II-C-2})$$

where

$$a_t = [(1 - L) * (\hat{\gamma}_{0t} + \hat{\delta}_{0t}) - (\hat{\alpha}_{0t} + \hat{\beta}_{0t})] / [(\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1)] \quad (\text{II-C-3})$$

$$b_t = \hat{\alpha}_1 / [(\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1)] \quad (\text{II-C-4})$$

and

$$a_t > 0 \quad \text{and} \quad 0 < b_t < 1.$$

Proof that $a_t > 0$. Consider the numerator of equation (II-C-3). The terms $\hat{\alpha}_{0t}$ and $\hat{\beta}_{0t}$ represent the horizontal intercepts of the Ontario-based demand and export curves, respectively, which are both positive by assumption. Thus, $\hat{\alpha}_{0t} + \hat{\beta}_{0t} > 0$. The terms $\hat{\gamma}_{0t}$ and $\hat{\delta}_{0t}$ represent the horizontal intercepts of the Ontario-based supply and import

curves, respectively, which are not necessarily positive. However, given that $0 < L < 1$, assuming $\hat{\gamma}_{0t} + \hat{\delta}_{0t} < \hat{\alpha}_{0t} + \hat{\beta}_{0t}$ implies that the numerator is negative, that is

$$(1 - L) * (\hat{\gamma}_{0t} + \hat{\delta}_{0t}) - (\hat{\alpha}_{0t} + \hat{\beta}_{0t}) < 0 \quad (\text{II-C-5})$$

This condition can loosely be interpreted as requiring that the sum of the horizontal intercepts of Ontario-based demand and exports be greater than a positive fraction of the sum of the horizontal intercepts of Ontario-based supply and imports. If this was not the case then the wholesale market clearing price could not be positive. This condition is analogous to the standard assumption that the choke price in a market must exceed the marginal cost of the first unit of production for a market to exist.

Now consider the denominator of equation (II-C-3). The terms $\hat{\alpha}_1$ and $\hat{\beta}_1$ represent the inverses of the slopes of the Ontario-based demand and export curves, respectively, which are both negative by assumption, while the terms $\hat{\gamma}_1$ and $\hat{\delta}_1$ represent the inverses of the slopes of the Ontario-based supply and import curves, respectively, which are both positive by assumption. That is, $\hat{\alpha}_1 < 0$, $\hat{\beta}_1 < 0$, $\hat{\gamma}_1 > 0$, and $\hat{\delta}_1 > 0$. As noted in-text, $0 < L < 1$. Thus

$$(\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1) < 0 \quad (\text{II-C-6})$$

Therefore $a_t > 0$. As an aside, consider the equilibrium that would obtain if the regulator's budget constraint did not exist, that is, in a five-equation model of the electricity market. First, $g_t = 0$. Second, all payments made by the regulator that are funded by the GA, including out-of-market top-up payments, would have to be funded from elsewhere in the economy, say, by the levying of a non-distortionary tax by the government. In this revised model, $a_t (> 0)$ would be the equilibrium wholesale market clearing price.

Proof that $0 < b_t < 1$. From the argument above, it can be stated that

$$0 > \hat{\beta}_1 - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1)$$

$$\Leftrightarrow 0 > \hat{\alpha}_1 > (\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1)$$

Noting that $(\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1) < 0$, then

$$0 < \frac{\hat{\alpha}_1}{(\hat{\alpha}_1 + \hat{\beta}_1) - (1 - L) * (\hat{\gamma}_1 + \hat{\delta}_1)} < 1$$

$$\Leftrightarrow 0 < b_t < 1 \quad (\text{II-C-7})$$

The regulator's budget constraint, equation (II-8), can be re-written using the fitted variables as

$$g_t * \hat{q}_t^d = CGR_t - P_t * q_t^{ga} \quad (\text{II-C-8})$$

where

$$\begin{aligned} CGR_t = & p_c^{wind} * q_t^{wind} + p_c^{solar} * q_t^{solar} * solar_capacity \\ & + p_c^{nugs} * q_t^{nugs} + p_c^{nuclear} * q_t^{nuclear} + p_c^{base_hydro} * q_t^{base_hydro} \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (\text{II-C-9})$$

and

$$q_t^{ga} = q_t^{wind} + q_t^{solar} * solar_capacity + q_t^{nugs} + q_t^{nuclear} + q_t^{base_hydro} \quad (\text{II-C-10})$$

The term CGR_t , an acronym for contracted generator revenue, represents the total revenue received from all sources by generators operating under a contract with the regulator that may give rise to payments funded by the global adjustment. As such, it is the product of each generator-type's contract price and total amount of output (across all firms), summed across all of the generator types, plus certain other expenses incurred by the regulator. The term q_t^{ga} represents the total amount of electricity

generated by all such generators. This quantity multiplied by the wholesale market clearing price, that is, $P_t * q_t^{ga}$, equals the amount of revenue contracted generators made in the wholesale market alone. The difference between these two amounts, which, as discussed in-text does not have to be non-negative, is the total amount of revenue received by contracted generators from sources other than the wholesale market. Since the only other source is the regulator, this term is equivalent to the amount of revenue raised by the regulator, that is, $g_t * q_t^d$. This relationship is summarised by equation (II-C-8).

Using equation (II-21), equation (II-C-8) can be re-written as

$$g_t * (\hat{\alpha}_{0t} + \hat{\alpha}_1(p_t + g_t)) = CGR_t - P_t * q_t^{ga} \quad (\text{II-C-11})$$

As a result of these operations, the original six-equation system of equations can be solved for a system of two equations, equations (II-C-2) and (II-C-11), with two unknowns, the wholesale market clearing price and the GA rate. Due to the regulator's budget constraint being quadratic in the GA rate, the system is not linear in nature. Instead, there will be two solutions. Substituting equation (II-C-2) into equation (II-C-8) yields a single equation that is quadratic in the GA rate, g_t

$$[\hat{\alpha}_1(1 - b_t)]g_t^2 + [\hat{\alpha}_{0t} + a_t\hat{\alpha}_1 - b_tq_t^{ga}]g_t + [a_tq_t^{ga} - CGR_t] = 0 \quad (\text{II-C-12})$$

Therefore

$$g_t = [-B_t \pm \sqrt{(B_t)^2 - 4A_tC_t}] / 2A_t \quad (\text{II-C-13})$$

where

$$A_t = \hat{\alpha}_1(1 - b_t) < 0 \quad (\text{II-C-14})^{153}$$

¹⁵³ Recalling that $\hat{\alpha}_1 < 0$ and $0 < b_t < 1$, it follows immediately that $A_t = \hat{\alpha}_1(1 - b_t) < 0$.

$$B_t = \hat{a}_{0t} + a_t \hat{a}_1 - b_t q_t^{ga} \quad (\text{II-C-15})$$

and

$$C_t = a_t q_t^{ga} - CGR_t \quad (\text{II-C-16})$$

The term C_t is not explicitly signed. The sign, however, is important as it indicates whether the GA rate is negative or positive. To see why, consider equation (A-9)

$$\begin{aligned} CGR_t = & p_c^{wind} * q_t^{wind} + p_c^{solar} * q_t^{solar} * solar_capacity \\ & + p_c^{nugs} * q_t^{nugs} + p_c^{nuclear} * q_t^{nuclear} + p_c^{base_hydro} * q_t^{base_hydro} \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (\text{II-C-9})$$

$$\begin{aligned} = & p_c^{average} * q_t^{ga} \\ & + nat_gas_capacity_t + contingency_t + conservation_t \end{aligned} \quad (\text{II-C-17})$$

where

$$\begin{aligned} p_c^{average} = & p_c^{wind} * \frac{q_t^{wind}}{q_t^{ga}} + p_c^{solar} * \frac{q_t^{solar}}{q_t^{ga}} * solar_capacity \\ & + p_c^{nugs} * \frac{q_t^{nugs}}{q_t^{ga}} + p_c^{nuclear} * \frac{q_t^{nuclear}}{q_t^{ga}} + p_c^{base_hydro} * \frac{q_t^{base_hydro}}{q_t^{ga}} \end{aligned} \quad (\text{II-C-18})$$

is a quantity-weighted average of the contract prices.

Substituting equation (II-C-17) into equation (II-C-16), then

$$\begin{aligned} C_t = & q_t^{ga} (a_t - p_c^{average}) \\ & - (nat_gas_capacity_t + contingency_t + conservation_t) \end{aligned} \quad (\text{II-C-19})$$

The term $(nat_gas_capacity_t + contingency_t + conservation_t)$ is positive since each of

its components is positive by definition. Now consider the term $(a_t - p_c^{average})$. The variable a_t , as noted above, is the wholesale market equilibrium price that would prevail if $g_t = 0$. Thus, if $a_t < p_c^{average}$, then the weighted average of contract prices exceeds the wholesale market clearing price that would prevail if $g_t = 0$. As a result, contacted generators are not, on average, able to make sufficient revenue in the wholesale market alone to satisfy the contracts and would therefore be entitled to positive (average) out-of-market top-up payments. The amount of such payments, aggregated across all contracted generators, is the negative of the first term of equation (II-C-19). Thus, $a_t < p_c^{average}$ is a sufficient (but not necessary) condition for $C_t < 0$. This is expected to be the case when relatively expensive generation types are weighted relatively highly in equation (II-C-18).

If $a_t > p_c^{average}$, then the weighted average of contract prices is less than the wholesale market price that would prevail if $g_t = 0$. As a result, contracted generators, on average, make more revenue in the wholesale market alone than is required to satisfy the contracts and would therefore be required to rebate the excess to the regulator in the form of negative (average) out-of-market top-up payments. The amount of such payments, aggregated across all contracted generators, is the first term of equation (II-C-19). Due to the term $(nat_gas_capacity_t + contingency_t + conservation_t)$, this alone does not guarantee that $C_t > 0$, but it is a necessary condition. That is, $g_t > 0$ may be necessary even if $a_t > p_c^{average}$ if regulator expenses related to certain other expenses are sufficiently large.

Equation (II-C-13) has two solutions. That is, there are two GA rates that allow equilibrium to obtain in the wholesale market, including the balancing of the regulator's budget. In order to maximise social welfare, the GA rate that is chosen is the one relatively small in absolute value. The rationale for this choice is that it, by definition, imposes the smallest distortion on the market. Denote this value as g_t^* .

The equilibrium wholesale market clearing price, denoted as p_t^* , is found by substituting g_t^* into equation (II-C-2). That is

$$p_t^* = a_t - b_t g_t^* \quad (\text{II-C-20})$$

The equilibrium Ontario-based supply, imports, Ontario-based demand, and exports can be found by substituting p_t^* and g_t^* into equations (II-14), (II-17), (II-21), and (II-24), respectively.

$$\hat{q}_t^{s*} = \hat{\gamma}_{0t} + \hat{\gamma}_1 p_t^* \quad (\text{II-C-21})$$

$$\hat{q}_t^{i*} = \hat{\delta}_{0t} + \hat{\delta}_1 p_t^* \quad (\text{II-C-22})$$

$$\hat{q}_t^{d*} = \hat{\alpha}_{0t} + \hat{\alpha}_1 (p_t^* + g_t^*) \quad (\text{II-C-23})$$

$$\hat{q}_t^{e*} = \hat{\beta}_{0t} + \hat{\beta}_1 p_t^* \quad (\text{II-C-24})$$

The values p_t^* , g_t^* , $\hat{q}_t^{s*}$, $\hat{q}_t^{i*}$, $\hat{q}_t^{d*}$, and $\hat{q}_t^{e*}$, constitute the base case equilibrium of the wholesale market model.

Appendix V-A: Acronyms

CDD	cooling degree days
FTR	financial transmission right
HDD	heating degree days
HOEP	hourly Ontario energy price
LT	long-term
ICP	intertie congestion price
IEEE	Institute of Electrical and Electronic Engineers
IESO	Independent Electricity System Operator
ISO	Independent System Operator
MCP	market clearing price
MSP	Market Surveillance Panel
MW	megawatt
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ST	short-term
TCC	transmission congestion contract

Appendix V-B: Numerical Example of an FTR

This appendix provides a brief numerical example regarding the functioning of an FTR as a hedge against transmission congestion.

For a given hour, if an intertie is congested in the direction for which an FTR holder owns an FTR, the holder is entitled to receive a payout equal the absolute value of the ICP for each FTR they hold.¹⁵⁴ Suppose an FTR holder owns 10 MW of export-oriented ST FTRs on the Ontario-Michigan interface for the month January 2011. Thus, in each export congested hour of January 2011 the FTR holder would receive a payout equal to 10 times the (already positive) ICP.¹⁵⁵

In each hour there are two possible outcomes: either no export congestion, that is either no congestion or import congestion, or export congestion. Suppose each outcome is equally likely. If there is no export congestion then the relevant ICP is \$0/MWh and the payout for the hour in question is \$0. Further, suppose that in the event of export congestion the relevant ICP was \$20/MWh, implying a payout of \$200. The expected ICP is then \$10/MWh, while the expected payout is \$100.

Suppose a trader contracts with an Ontario-based generator to purchase 10 MWh of electricity for \$100/MWh and sells it to a Michigan-based customer for \$120/MWh. Assume transactions costs are \$5/MWh. If there is no export congestion then the trader will earn \$15/MWh, for a total profit of \$150.¹⁵⁶ If there is export congestion then the

¹⁵⁴ Recall from section II that FTRs are sold in one MW increments, that is, one FTR equals one MW on a given path. Also recall that payouts are always non-negative.

¹⁵⁵ There are a small number of additional considerations applicable to this calculation, though they are minor and are ignored.

¹⁵⁶ Profit is equal to the Michigan consumer price less the ICP, less the Ontario purchase price, less transactions costs, for each of the 10 FTRs: $\$150 = (\$120 - \$0 - \$100 - \$5)/\text{MWh} * 10 \text{ MWh}$.

trader will earn -\$5/MWh, for a total of -\$50 (a loss of \$50).¹⁵⁷ Given that these two situations are equally likely, the trader's expected profit is \$50.

To hedge against the risk of congestion incumbent in this scenario, the trader may purchase FTRs on this path. Suppose the trader is risk neutral and the MCP is \$10/MWh—the expected payout—for each of 10 FTRs at auction. Then the trader's profit will be \$50 regardless of the congestion pattern.¹⁵⁸ This result is independent of the level of the MCP. Risk averse traders would be willing to pay more than \$10/MWh, while risk loving traders would not be willing to pay as much.

¹⁵⁷ Profit is equal to the Michigan consumer price less the ICP, less the Ontario purchase price, less transactions costs, for each of the 10 FTRs: $-\$50 = (\$120 - \$20 - \$100 - \$5)/\text{MWh} * 10 \text{ MWh}$.

¹⁵⁸ Profit is equal to the Michigan consumer price less the ICP, plus payout (ICP), less the Ontario purchase price, less FTR purchase price, less transactions costs, for each of the 10 FTRs. With no export congestion: $\$50 = (\$120 + \$0 - \$0 - \$100 - \$10 - \$5)/\text{MWh} * 10 \text{ MWh}$. With export congestion: $\$50 = (\$120 - \$20 + \$20 - \$100 - \$10 - \$5)/\text{MWh} * 10 \text{ MWh}$.

Appendix V-C: Complete List of Transmission Paths

Path Name	Source	Sink
MBSI to ONZN	Manitoba	Ontario
MISI to ONZN	Michigan	Ontario
MNSI to ONZN	Minnesota	Ontario
NYSI to ONZN	New York	Ontario
PQAT to ONZN	Quebec AT	Ontario
PQBE to ONZN	Quebec BE	Ontario
PQDA to ONZN	Quebec DA	Ontario
PQDZ to ONZN	Quebec DZ	Ontario
PQPC to ONZN	Quebec PC	Ontario
PQXY to ONZN	Quebec XY	Ontario
ONZN to MBSI	Ontario	Manitoba
ONZN to MISI	Ontario	Michigan
ONZN to MNSI	Ontario	Minnesota
ONZN to NYSI	Ontario	New York
ONZN to PQAT	Ontario	Quebec AT
ONZN to PQDA	Ontario	Quebec DA
ONZN to PQHZ	Ontario	Quebec HZ

Appendix V-D: ST FTR data and statistics

Table V-D1: ST FTR: MCP and payout summary statistics ignoring path distinction

Variable	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
Payout	296	604.0	1,339.2	3.76	21.47	0.00	11,211.82
MCP	296	510.3	804.6	3.42	18.64	0.01	5,780.88

Table V-D2: ST FTR: MCP and payout summary statistics for import paths

Source	Variable	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
MISI	Payout	74	739.9	1,515.3	2.95	11.95	0.00	7,748.86
MISI	MCP	74	601.6	640.4	0.80	2.39	1.71	2,269.20
NYSI	Payout	75	193.5	807.9	5.09	28.89	0.00	5,144.12
NYSI	MCP	75	136.2	161.3	1.49	4.34	3.00	662.16

Table V-D3: ST FTR: MCP and payout summary statistics for export paths

Sink	Variable	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
MISI	Payout	74	413.5	914.7	3.03	11.86	0.00	4,652.24
MISI	MCP	74	383.3	968.6	4.64	25.25	0.01	5,780.88
NYSI	Payout	73	1,081.1	1,743.3	3.30	17.56	0.00	11,211.82
NYSI	MCP	73	931.0	953.0	2.26	8.51	10.00	4,898.00

Table V-D4: ST FTR: Summary Statistics for ex-post profits

Path	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
All paths considered	296	93.66	1,213.71	3.45	22.43	-3,102.22	9,902.38
MISI to ONZN	74	138.34	1,289.29	2.71	12.06	-2,004.61	6,248.86
NYSI to ONZN	75	57.32	828.72	4.75	26.64	-658.26	5,044.24
ONZN to MISI	74	30.19	924.17	1.71	13.67	-3,102.22	4,357.24
ONZN to NYSI	73	150.03	1,663.63	3.25	18.40	-2,387.21	9,902.38

Table V-D5: ST FTR: Correlation between MCP and payout and its statistical significance for paths under consideration

Path	Corr. Coefficient	p-value¹⁵⁹
All paths considered	0.4490	0.0000
MISI to ONZN	0.5379	0.0000
NYSI to ONZN	-0.0309	0.7921
ONZN to MISI	0.5196	0.0000
ONZN to NYSI	0.3550	0.0021

Table V-D6: ST FTR: Summary statistics for various additional variables

Variable	N	Mean	Std. Dev.	Minimum	Maximum
1 / t	86	0.06	0.13	0.01	1.00
Natural Gas Price	86	6.66	1.97	3.22	12.19
Natural Gas Capacity Ratio	86	0.47	0.08	0.37	0.68
Risk-free Interest Rate	86	2.24	1.42	0.12	4.29
HDD PosDev onzn	86	26.19	90.74	0.00	506.20
HDD NegDev onzn	86	30.76	44.64	0.00	215.50
CDD PosDev onzn	86	6.26	16.40	0.00	80.80
CDD NegDev onzn	86	4.72	13.41	0.00	65.00
HDD PosDev misi	86	12.28	23.76	0.00	111.70
HDD NegDev misi	86	17.01	28.93	0.00	178.20
CDD PosDev misi	86	5.29	12.73	0.00	68.00
CDD NegDev misi	86	5.74	13.28	0.00	73.80
HDD PosDev nysi	86	8.97	20.71	0.00	121.80
HDD NegDev nysi	86	14.34	28.30	0.00	139.00
CDD PosDev nysi	86	6.35	14.19	0.00	61.30
CDD NegDev nysi	86	5.52	14.14	0.00	73.30

¹⁵⁹ The p-value relates the test of statistical significance of the correlation coefficient, where the null and alternative hypotheses are that the correlation is zero and otherwise, respectively.

Figure V-D1: Scatter plot of MCP against payout for paths under consideration

Panel A: All paths together

Panel B: Path-by-path

Figure V-D2: ST FTR: Time series plots of MCP and payout for paths under consideration

Appendix V-E: Estimation results for pooled ST FTR data

Table V-E1: OLS on pooled cross-section: Estimates and diagnostic tests

	Model (I)	Model (II)	Model (III)	Model (IV)
MCP	0.666 (0.123)****	0.550 (0.152)****	0.648 (0.119)****	0.502 (0.150)****
1 / t		-612.205 (1157.396)		116.393 (1174.935)
MCP / t		3.519 (3.758)		4.451 (3.841)
Natural gas price			-698.729 (444.198)	-823.973 (437.854)*
Natural gas capacity ratio			-6358.560 (5343.439)	-5994.569 (5406.783)
NG price * NG capacity ratio			1801.989 (900.358)**	2167.606 (881.829)**
Risk-free rate			-95.337 (48.634)*	-54.333 (47.685)
Constant	448.649 (108.296)****	413.054 (135.897)***	3005.781 (2902.257)	2401.202 (2994.329)
R-square	0.231	0.245	0.254	0.281
Adj. R-square	0.218	0.226	0.230	0.253
AIC	5035.448	5034.246	5034.672	5027.791
BIC	5057.590	5063.768	5071.576	5072.075
Root MSE	1184.237	1177.945	1174.944	1157.599
Overall F-stat	17.456 (0.000)	13.332 (0.000)	10.808 (0.000)	10.077 (0.000)
n	296	296	296	296
Break=0 F-stat	2.797 (0.026)	2.380 (0.052)	3.555 (0.008)	3.608 (0.007)
Condition No.	1.82	1.82	1.82	1.82
Mean VIF	1.00	1.00	1.00	1.00
BP, standard	0.000	0.000	0.000	0.000
BP, N*R2	0.004	0.001	0.000	0.000
BP, F-stat	0.004	0.001	0.000	0.000
White's test	0.042	0.327	0.101	0.129
Skew-kurt test	0.00	0.00	0.00	0.00
Linktest	-0.716	0.360	-0.105	1.264
RESET test	0.14	0.23	0.00	0.00

Note: Huber-White standard errors reported in parentheses. Structural break dummy variable estimates omitted from the table. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (number) and Mean VIF, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-E2: OLS on pooled cross-section: Hypothesis test results

	Model (I)	Model (II)	Model (III)	Model (IV)
Hypothesis A	17.2 (0.000)	9.2 (0.003)	1.1 (0.301)	0.6 (0.423)
Hypothesis B	29.5 (0.000)	13.1 (0.000)	29.6 (0.000)	11.2 (0.001)
Hypothesis C	7.4 (0.007)	8.8 (0.003)	8.8 (0.003)	11.1 (0.001)
Hypothesis D	11.6 (0.000)	9.3 (0.000)	4.5 (0.011)	5.6 (0.004)
Hypothesis E		0.3 (0.597)		0.0 (0.921)
Hypothesis F		0.9 (0.350)		1.3 (0.248)
Hypothesis G		0.4 (0.642)		1.1 (0.347)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-E3: Tobit on pooled cross-section: Estimates and diagnostic tests

	Model (I)	Model (II)	Model (III)	Model (IV)
MCP	0.872 (0.165)****	0.654 (0.187)****	0.822 (0.158)****	0.551 (0.182)***
1 / t		-2140.950 (2469.952)		-977.616 (2241.654)
MCP / t		6.560 (4.512)		8.166 (4.433)*
Natural gas price			-878.432 (657.668)	-1166.868 (636.639)*
Natural gas capacity ratio			-7125.963 (7820.418)	-8124.681 (7528.876)
NG price * NG capacity ratio			2311.879 (1362.853)*	3065.828 (1327.482)**
Risk-free rate			-24.111 (88.566)	37.378 (89.301)
Constant	-77.580 (142.279)	-55.980 (192.805)	2372.853 (4210.703)	2281.941 (4121.619)
Sigma	1584.537 (223.985)****	1565.118 (218.304)****	1555.954 (208.970)****	1515.940 (192.731)****
MacKinnon R2	0.031	0.034	0.034	0.038
McK.-Zav. R2	0.324	0.343	0.348	0.381
Cragg-Uhl. R2	0.296	0.315	0.316	0.348
Cox-Snell R2	0.296	0.315	0.316	0.348
AIC	3249.551	3245.317	3248.939	3238.670
BIC	3275.384	3278.530	3289.533	3286.645
Break=0 F-test	7.113 (0.000)	7.115 (0.000)	8.442 (0.000)	9.013 (0.000)
Chi2-stat.	103.760 (0.000)	111.994 (0.000)	112.372 (0.000)	126.641 (0.000)
Overall F-stat.	11.465 (0.000)	9.230 (0.000)	8.173 (0.000)	7.663 (0.000)
n	296	296	296	296

Note: Huber-White standard errors reported in parentheses. Structural break dummy variable estimates omitted from the table.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-E4: Tobit on pooled cross-section: Hypothesis test results

	Model (I)	Model (II)	Model (III)	Model (IV)
Hypothesis A	0.3 (0.586)	0.1 (0.772)	0.3 (0.574)	0.3 (0.580)
Hypothesis B	28.0 (0.000)	12.3 (0.001)	27.1 (0.000)	9.1 (0.003)
Hypothesis C	0.6 (0.437)	3.4 (0.065)	1.3 (0.259)	6.1 (0.014)
Hypothesis D	0.9 (0.408)	2.3 (0.106)	0.7 (0.487)	3.1 (0.046)
Hypothesis E		0.8 (0.387)		0.2 (0.663)
Hypothesis F		2.1 (0.147)		3.4 (0.067)
Hypothesis G		1.1 (0.326)		2.2 (0.115)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-E5: Panel data with fixed path-specific effects: Estimates and diagnostic tests

	Model (I)	Model (II)	Model (III)	Model (IV)
MCP	0.510 (0.092)**	0.504 (0.105)**	0.471 (0.049)***	0.453 (0.072)***
1 / t		-112.569 (1231.685)		606.713 (1210.669)
MCP / t		0.213 (2.458)		1.233 (2.251)
Natural gas price			-940.128 (365.938)*	-935.233 (311.933)*
Natural gas capacity ratio			-7883.623 (3602.403)	-6789.600 (2759.859)*
NG price * NG capacity ratio			2344.709 (672.288)**	2391.587 (593.551)**
Risk-free rate			-21.170 (51.837)	-4.744 (64.143)
Constant	625.297 (53.390)***	629.790 (61.712)***	3773.362 (2218.724)	2966.302 (1847.416)
corr(u _i , Xb)	-0.440	-0.433	-0.514	-0.459
s.e. u _i	543.650	536.045	612.292	546.291
s.e. e _{it}	1155.361	1159.350	1137.976	1137.207
Rho	0.181	0.176	0.225	0.187
All u _i =0 F-test	5.893 (0.001)	4.104 (0.007)	7.295 (0.000)	4.426 (0.005)
Overall R2	0.176	0.178	0.192	0.214
Log Likelihood	-2502.878	-2502.863	-2496.313	-2495.063

Overall F-test	16.886 (0.000)	11.982 (0.000)	11.096 (0.000)	9.307 (0.000)
n	296	296	296	296
Breaks=0 F-test	6.453 (0.000)	4.735 (0.001)	8.054 (0.000)	5.953 (0.000)
Wald HC test	0.030	0.036	0.055	0.064
Woold. AC test	0.029	0.027	0.046	0.044
BP CD test	0.077	0.089	0.193	0.367
Pesaran test	0.028	0.017	0.093	0.094

Note: Huber-White robust panel standard errors are reported in parentheses.

Coefficient estimates are common among the three cases. 'corr(u_i, Xb)' refers to the correlation between u_i and the regressors listed. 'Rho' refers to the fraction of variation that is due to u_i. HC, AC, and CD denote heteroskedasticity, autocorrelation, and cross-sectional dependence, respectively (reported figures are p-values).

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-E6: Panel data with fixed path-specific effects: Hypothesis test results

	Model (I)	Model (II)	Model (III)	Model (IV)
Hypothesis A	137.2 (0.001)	104.1 (0.002)	2.9 (0.188)	2.6 (0.207)
Hypothesis B	30.9 (0.011)	22.9 (0.017)	91.1 (0.002)	40.0 (0.008)
Hypothesis C	28.6 (0.013)	22.1 (0.018)	115.1 (0.002)	58.4 (0.005)
Hypothesis D	137.2 (0.001)	53.5 (0.005)	109.6 (0.002)	29.5 (0.011)
Hypothesis E		0.0 (0.933)		0.3 (0.651)
Hypothesis F		0.0 (0.936)		0.3 (0.622)
Hypothesis G		0.0 (0.993)		2.0 (0.286)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-E7: Tobit with dummy variables on pooled cross-section: Estimates and diagnostic tests

	Model (I)	Model (II)	Model (III)	Model (IV)
MCP	0.593 (0.117)****	0.552 (0.161)****	0.483 (0.119)****	0.422 (0.166)**
1 / t		-1012.884 (2314.202)		19.815 (2158.644)
MCP / t		1.427 (5.563)		3.008 (5.499)
Natural gas price			-1229.564 (677.859)*	-1277.082 (660.321)*
Natural gas capacity ratio			-9786.897 (7790.097)	-9304.917 (7629.767)
NG price * NG capacity ratio			3119.249 (1390.408)**	3288.392 (1363.232)**
Risk-free rate			109.114 (84.669)	121.545 (88.441)
Constant	1283.383 (401.666)***	1277.418 (505.323)**	4872.424 (4237.664)	4130.773 (4289.195)
Sigma	1521.815 (220.914)****	1521.497 (219.828)****	1473.989 (205.090)****	1466.571 (196.195)****
MacKinnon R2	0.039	0.040	0.044	0.045
McK.-Zav. R2	0.378	0.380	0.420	0.426
Cragg-Uhl. R2	0.358	0.360	0.392	0.396
Cox-Snell R2	0.358	0.360	0.392	0.396
AIC	3227.973	3231.092	3219.913	3221.851
BIC	3264.876	3275.377	3271.578	3280.897
Break=0 F-test	9.552 (0.000)	7.603 (0.000)	12.088 (0.000)	9.427 (0.000)
Overall F-stat.	9.598 (0.000)	8.393 (0.000)	8.067 (0.000)	7.582 (0.000)
n	296	296	296	296

Note: Huber-White standard errors reported in parentheses. Structural break dummy variable estimates omitted from the table.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-E8: Tobit with dummy variables on pooled cross-section: Hypothesis test results

	Model (I)	Model (II)	Model (III)	Model (IV)
Hypothesis B	25.5 (0.000)	11.7 (0.001)	16.6 (0.000)	6.5 (0.012)
Hypothesis C	12.0 (0.001)	7.7 (0.006)	18.9 (0.000)	12.1 (0.001)
Hypothesis E		0.2 (0.662)		0.0 (0.993)
Hypothesis F		0.1 (0.798)		0.3 (0.585)
Hypothesis G		0.1 (0.903)		0.3 (0.759)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-E9: Panel Tobit with fixed-effects: Estimates and diagnostic tests

	Model (I)	Model (II)	Model (III)	Model (IV)
MCP	0.699 (0.182)****	0.586 (0.197)***	0.639 (0.121)****	0.500 (0.164)***
1 / t		-2967.355 (5594.541)		-254.771 (3120.609)
MCP / t		4.477 (5.663)		8.802 (2.154)****
Natural gas price			-1069.591 (2275.172)	-1680.799 (1926.247)
Natural gas capacity ratio			-8754.408 (21016.952)	-11052.980 (18566.424)
NG price * NG capacity ratio			3518.055 (4275.340)	4996.557 (3677.296)
Risk-free rate			102.970 (278.524)	104.331 (178.862)
Constant	448.649	413.054	3005.781	2401.202
Chi2-stat.	512.730 (0.000)	163.270 (0.000)	81.130 (0.000)	35.200 (0.000)
n	296	296	296	296

Note: The fixed-effects Tobit procedure is due to Honoré (1992). Estimates Unadjusted standard errors reported in parentheses. A standard error is not generated for the constant term.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-E10: Panel Tobit with fixed-effects: Hypothesis test results

	Model (I)	Model (II)	Model (III)	Model (IV)
Hypothesis B	14.8 (0.000)	8.9 (0.003)	28.0 (0.000)	9.3 (0.002)
Hypothesis C	2.7 (0.098)	4.4 (0.035)	8.9 (0.003)	9.3 (0.002)
Hypothesis E		0.3 (0.596)		0.0 (0.935)
Hypothesis F		0.6 (0.429)		16.7 (0.000)
Hypothesis G		1.1 (0.571)		69.1 (0.000)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-E11: Panel data with random path-specific effects: Estimates and diagnostic tests

	Model (I)	Model (II)	Model (III)	Model (IV)
MCP	0.666 (0.094)****	0.550 (0.082)****	0.648 (0.104)****	0.502 (0.046)****
1 / t		-612.205 (1177.992)		116.393 (1183.613)
MCP / t		3.519 (2.121)*		4.451 (1.633)***
Natural gas price			-698.729 (363.537)*	-823.973 (262.742)***
Natural gas capacity ratio			-6358.560 (4087.864)	-5994.569 (3092.269)*
NG price * NG capacity ratio			1801.989 (665.401)***	2167.606 (470.274)****
Risk-free rate			-95.337 (50.359)*	-54.333 (59.900)
Constant	448.649 (154.553)***	413.054 (172.282)**	3005.781 (2315.729)	2401.202 (1851.956)
s.e. u_i	0	0	0	0
s.e. e_it	1155.361	1159.350	1137.976	1137.207
Rho	0.000	0.000	0.000	0.000
Breaks=0 chi2	11.189 (0.025)	9.522 (0.049)	14.222 (0.007)	14.431 (0.006)
BP RE test	0.710	0.640	0.957	0.900
Pesaran test	0.019	0.012	0.058	0.064
Overall R2	0.231	0.245	0.254	0.281
Over. chi2-test	87.281 (0.000)	93.322 (0.000)	97.273 (0.000)	110.844 (0.000)
N	296	296	296	296

Note: Huber-White robust panel standard errors are reported in parentheses. 'Rho' refers to the fraction of variation that is due to u_i .

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table V-E12: Panel data with random path-specific effects: Hypothesis test results

	Model (I)	Model (II)	Model (III)	Model (IV)
Hypothesis A	8.4 (0.004)	5.7 (0.017)	1.7 (0.194)	1.7 (0.195)
Hypothesis B	49.7 (0.000)	44.4 (0.000)	39.1 (0.000)	119.6 (0.000)
Hypothesis C	12.5 (0.000)	29.8 (0.000)	11.6 (0.001)	117.9 (0.000)
Hypothesis D	358.8 (0.000)	65.6 (0.000)	12.1 (0.002)	118.8 (0.000)
Hypothesis E		0.3 (0.603)		0.0 (0.922)
Hypothesis F		2.8 (0.097)		7.4 (0.006)
Hypothesis G		5.2 (0.073)		157.7 (0.000)

Note: This table reports Chi2-statistics, with associated p-values in parentheses.

Table V-E13: Tobit with random path-specific effects: Estimates and diagnostic tests

	Model (I)	Model (II)	Model (III)	Model (IV)
MCP	0.636 (0.136)****	0.654 (0.147)****	0.522 (0.143)****	0.551 (0.153)****
1 / t		-2140.853 (1147.769)*		-977.616 (1148.547)
MCP / t		6.560 (2.336)***		8.166 (2.310)****
Natural gas price			-1180.511 (808.924)	-1166.868 (817.956)
Natural gas capacity ratio			-9414.742 (9470.161)	-8124.681 (9673.330)
NG price * NG capacity ratio			3008.561 (1782.062)*	3065.828 (1804.354)*
Risk-free rate			93.165 (123.170)	37.378 (122.316)
Constant	70.624 (395.624)	-55.977 (183.726)	3319.771 (4667.158)	2281.941 (4776.058)
Sigma of u_i	713.973 (304.933)**	0.000 ---	837.268 (340.072)**	0.000 ---
Sigma of e_{it}	1531.701	1565.106	1484.115	1515.940

	(83.421)****	(85.199)****	(80.602)****	(82.341)****
Log likelihood	-1611.433	-1613.658	-1604.041	-1606.335
AIC	3238.866	3247.317	3232.081	3240.670
BIC	3268.388	3284.220	3276.366	3292.335
Over. chi2-test	87.762 (0.000)	112.918 (0.000)	103.183 (0.000)	129.572 (0.000)
N	296	296	296	296

Note: Unadjusted standard errors reported in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-E14: Tobit with random path-specific effects: Hypothesis test results

	Model (I)	Model (II)	Model (III)	Model (IV)
Hypothesis A	0.0 (0.858)	0.1 (0.761)	0.5 (0.477)	0.2 (0.633)
Hypothesis B	22.0 (0.000)	19.8 (0.000)	13.4 (0.000)	13.0 (0.000)
Hypothesis C	7.2 (0.007)	5.5 (0.019)	11.2 (0.001)	8.7 (0.003)
Hypothesis D	7.3 (0.026)	7.2 (0.027)	11.8 (0.003)	8.8 (0.012)
Hypothesis E		3.5 (0.062)		0.7 (0.395)
Hypothesis F		7.9 (0.005)		12.5 (0.000)
Hypothesis G		7.9 (0.019)		14.3 (0.001)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-E15: Hausman test: Comparison of linear fixed- and random-effects models

	Model (I)	Model (II)	Model (III)	Model (IV)
Hausman test p-value	0.003	0.052	0.004	0.194

Table V-E16: Hausman-like comparison: Estimates of β under censored data estimators

	Model (I)	Model (II)	Model (III)	Model (IV)
FE Tobit	0.593 (0.117)****	0.552 (0.161)****	0.483 (0.119)****	0.422 (0.166)**
FE Honoré	0.699 (0.182)****	0.586 (0.197)***	0.639 (0.121)****	0.500 (0.164)***
RE Tobit	0.636 (0.136)****	0.654 (0.147)****	0.522 (0.143)****	0.551 (0.153)****
Diff. of RE from Honoré	-9.0%	+11.6%	-18.3%	+10.2%
RE within 95% CI of FE	Yes	Yes	Yes	Yes

Note: The percentage difference between RE Tobit and Honoré ("Diff. of RE from Honoré") considers as the base. A positive deviation implies RE Tobit estimate is smaller than Honoré.

Appendix V-F: Estimation results for path-by-path OLS analysis with ST FTR data

Table V-F1: Panel A: OLS: misi to onzn: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	1.273 (0.235)****	1.273 (0.404)****	0.805 (0.291)***	0.805 (0.525)
1 / t			-3514.000 (2170.748)	-3514.000 (2916.216)
MCP / t			7.767 (3.202)**	7.767 (5.863)
Constant	-25.730 (205.807)	-25.730 (118.931)	57.897 (210.549)	57.897 (127.132)
R-square	0.289		0.352	
Adj. R-square	0.279		0.324	
AIC	1271.579		1268.794	
BIC	1276.187		1278.010	
Root MSE	1286.245		1246.036	
Overall F-stat	29.310 (0.000)	9.925 (0.002)	12.651 (0.000)	6.386 (0.001)
n	74	74	74	74
Condition No.	2.32		5.78	
Mean VIF	1.00		3.55	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.001		0.002	
DW value	1.19		1.26	
Skew-kurt test	0.000	-0.000	0.000	0.000
Linktest	-0.28	-0.23	1.58	1.03
RESET test	0.016		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F1: Panel B: OLS: misi to onzn: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	0.746 (0.340)**	0.746 (0.372)**	0.248 (0.382)	0.248 (0.398)
HDD PosDev onzn	-2.466 (1.551)	-2.446 (1.199)**	-1.591 (1.552)	-1.591 (1.233)
HDD NegDev onzn	1.889 (6.325)	1.889 (3.457)	-1.801 (6.247)	-1.801 (4.378)
CDD PosDev onzn	-17.758 (13.553)	-17.758 (19.228)	-20.113 (13.073)	-20.113 (18.608)
CDD NegDev onzn	-53.193 (23.523)**	-53.193 (21.132)**	-53.911 (22.728)**	-53.911 (21.365)**
HDD PosDev misi	12.506 (6.116)**	12.506 (11.239)	8.542 (6.106)	8.542 (7.070)
HDD NegDev misi	-8.599 (9.203)	-8.599 (4.797)*	-3.950 (9.040)	-3.950 (5.865)
CDD PosDev misi	52.802 (17.923)***	52.802 (30.295)*	57.836 (17.382)***	57.836 (30.346)*
CDD NegDev misi	28.018 (24.294)	28.018 (17.072)	34.477 (23.501)	34.477 (16.399)**
Natural gas price	2745.552 (1250.595)**	2745.552 (1154.469)**	1997.574 (1236.662)	1997.574 (1361.119)
Natural gas capacity ratio	23831.689 (14259.734)*	23831.689 (11201.093)**	19074.383 (13910.887)	19074.383 (12229.859)
NG price * NG capacity ratio	-5755.624 (2722.212)**	-5755.624 (2564.675)**	-3839.983 (2724.845)	-3839.983 (2999.414)
Risk-free	-271.713 (151.297)*	-271.713 (113.826)*	-196.227 (150.538)	-196.227 (124.479)
1 / t			-3058.292 (2003.020)	-3058.292 (2522.572)
MCP / t			8.313 (3.317)**	8.313 (5.746)
Constant	-11253.652 (6940.874)	-11253.652 (5228.575)**	-9919.170 (6769.070)	-9919.170 (5664.815)*
R-square	0.554		0.601	
Adj. R-square	0.457		0.498	
AIC	1261.116		1256.875	
BIC	1293.372		1293.740	

Root MSE	1116.309		1073.905	
Overall F-stat	5.731 (0.000)	2.480 (0.000)	5.822 (0.000)	3.392 (0.000)
n	74	74	74	74
Condition No.	308.19		326.42	
Mean VIF	49.51		46.32	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.445		0.445	
DW value	1.68		1.82	
Skew-kurt test	0.000	0.000	0.001	0.001
Linktest	6.73	4.10	6.67	
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F1: Panel C: OLS: misi to onzn: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	1.110 (0.244)****	1.110 (0.370)***	0.273 (0.317)	0.273 (0.477)
Lag of Profit	0.399 (0.117)***	0.399 (0.171)**	0.389 (0.108)****	0.389 (0.189)**
1 / t			-21927.751 (7384.836)***	-21927.751 (13782.050)
MCP / t			22.927 (6.639)***	22.927 (13.422)*
Constant	42.587 (215.089)	42.587 (124.992)	541.899 (261.715)**	541.899 (273.913)**
R-square	0.403		0.513	
Adj. R-square	0.384		0.481	
AIC	1131.176		1121.654	
BIC	1137.745		1132.602	
Root MSE	1246.862		1143.757	
Overall F-stat	21.224 (0.000)	12.937 (0.000)	16.079 (0.000)	10.183 (0.000)
n	66	66	66	66
Condition No.	2.50		12.85	
Mean VIF	1.06		10.21	
BP, standard	0.000		0.000	
BP, N*R2	0.024		0.000	
BP, F-stat	0.024		0.000	
White's test	0.157		0.054	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-0.49	-0.36	1.35	0.88
RESET test	0.894		0.393	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F1: Panel D: OLS: misi to onzn: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	0.724 (0.379)*	0.724 (0.421)*	-0.907 (0.502)*	-0.907 (0.558)
HDD PosDev onzn	-2.271 (1.595)	-2.271 (1.169)*	-1.948 (1.439)	-1.948 (1.160)*
HDD NegDev onzn	-1.888 (6.802)	-1.888 (3.489)	-3.122 (5.987)	-3.122 (4.412)
CDD PosDev onzn	-18.837 (14.215)	-18.837 (19.910)	-17.160 (12.386)	-17.160 (20.080)
CDD NegDev onzn	-25.074 (28.058)	-25.074 (19.306)	-56.892 (25.570)**	-56.892 (25.570)*
HDD PosDev misi	17.508 (7.250)**	17.508 (15.215)	3.690 (7.075)	3.690 (5.833)
HDD NegDev misi	-3.068 (10.231)	-3.068 (5.866)	-0.510 (8.932)	-0.510 (6.728)
CDD PosDev misi	51.100 (19.516)**	51.100 (33.314)	56.223 (17.096)***	56.223 (34.143)
CDD NegDev misi	8.626 (26.954)	8.626 (13.798)	35.683 (24.258)	35.683 (20.723)*
Natural gas price	1793.237 (1479.514)	1793.237 (1277.516)	2922.151 (1353.037)**	2922.151 (1662.009)*
Natural gas capacity ratio	14618.175 (16414.514)	14618.175 (11963.602)	22521.439 (14451.276)	22521.439 (15126.439)
NG price * NG capacity ratio	-3805.072 (3171.072)	-3805.072 (2737.074)	-5809.586 (2918.216)*	-5809.586 (3546.519)
Risk-free	-235.368 (172.250)	-235.368 (136.873)*	-216.075 (152.057)	-216.075 (131.422)
Lag of Profit	0.264 (0.133)*	0.264 (0.129)**	0.151 (0.119)	0.151 (0.156)
1 / t			-30984.075 (8323.976)****	-30984.075 (10163.193)***
MCP / t			30.590 (7.290)****	30.590 (9.596)***
Constant	-6580.702 (8085.428)	-6580.702 (5756.909)	-10640.465 (7090.717)	-10640.465 (7213.648)
R-square	0.603		0.712	
Adj. R-square	0.494		0.618	

AIC	1128.156		1110.986	
BIC	1161.001		1148.210	
Root MSE	1129.282		981.386	
Overall F-stat	5.539 (0.000)	3.704 (0.000)	7.576 (0.000)	7.141 (0.000)
n	66	66	66	66
Condition No.	337.40		326.42	
Mean VIF	53.25		46.32	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.442		0.442	
Skew-kurt test	0.000	0.000	0.027	0.027
Linktest	4.47	3.63	3.96	4.27
RESET test	0.000		0.000	

Point estimates from OLS and Newey-West estimation approaches are the same.

Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F2: Panel A: OLS: misi to onzn: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	0.0 (0.901)	0.0 (0.829)	0.1 (0.784)	0.2 (0.650)
Hypothesis B	29.3 (0.000)	9.9 (0.002)	7.6 (0.007)	2.4 (0.129)
Hypothesis C	1.3 (0.250)	0.5 (0.502)	0.4 (0.506)	0.1 (0.712)
Hypothesis D	1.1 (0.338)	0.3 (0.735)	0.2 (0.787)	0.1 (0.901)
Hypothesis E			2.6 (0.110)	1.5 (0.232)
Hypothesis F			5.9 (0.018)	1.8 (0.190)
Hypothesis G			3.4 (0.040)	1.0 (0.385)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F2: Panel B: OLS: misi to onzn: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	2.6 (0.110)	4.6 (0.035)	2.1 (0.148)	3.1 (0.085)
Hypothesis B	4.8 (0.032)	4.0 (0.049)	0.4 (0.518)	0.4 (0.534)
Hypothesis C	0.6 (0.459)	0.5 (0.497)	3.9 (0.054)	3.6 (0.064)
Hypothesis D	1.4 (0.267)	2.4 (0.101)	2.5 (0.088)	2.7 (0.075)
Hypothesis E			2.3 (0.132)	1.5 (0.230)
Hypothesis F			6.3 (0.015)	2.1 (0.153)
Hypothesis G			3.4 (0.040)	1.1 (0.335)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F2: Panel C: OLS: misi to onzn: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	0.0 (0.844)	0.1 (0.734)	4.3 (0.043)	3.9 (0.052)
Hypothesis B	20.7 (0.000)	9.0 (0.004)	0.7 (0.393)	0.3 (0.569)
Hypothesis C	0.2 (0.653)	0.1 (0.766)	5.2 (0.025)	2.3 (0.133)
Hypothesis D	0.4 (0.702)	0.4 (0.654)	2.8 (0.070)	2.0 (0.150)
Hypothesis E			8.8 (0.004)	2.5 (0.117)
Hypothesis F			11.9 (0.002)	2.9 (0.093)
Hypothesis G			6.9 (0.002)	1.8 (0.178)
Hypothesis J	11.6 (0.001)	5.4 (0.023)	13.0 (0.001)	4.2 (0.044)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F2: Panel D: OLS: misi to onzn: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	0.7 (0.419)	1.3 (0.258)	2.3 (0.140)	2.2 (0.147)
Hypothesis B	3.7 (0.062)	3.0 (0.092)	3.3 (0.077)	2.6 (0.110)
Hypothesis C	0.5 (0.469)	0.4 (0.514)	14.4 (0.000)	11.7 (0.001)
Hypothesis D	0.4 (0.642)	0.7 (0.516)	7.3 (0.002)	6.0 (0.005)
Hypothesis E			13.9 (0.001)	9.3 (0.004)
Hypothesis F			17.6 (0.000)	10.2 (0.002)
Hypothesis G			9.3 (0.000)	5.1 (0.010)
Hypothesis J	3.9 (0.053)	4.2 (0.046)	1.6 (0.211)	0.9 (0.338)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F3: Panel A: OLS: *nysi* to *onzn*: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	-0.155 (0.586)	-0.155 (0.166)	0.132 (0.621)	0.132 (0.153)
1 / t			5879.442 (1025.504)****	5879.442 (315.745)****
MCP / t			-12.696 (4.048)***	-12.696 (1.518)****
Constant	214.662 (123.228)*	214.662 (118.987)*	-1.638 (109.316)	-1.638 (95.108)
R-square	0.001		0.355	
Adj. R-square	-0.013		0.328	
AIC	1219.928		1191.064	
BIC	1224.563		1200.334	
Root MSE	813.027		662.193	
Overall F-stat	0.070 (0.792)	0.843 (0.362)	13.050 (0.000)	236.412 (0.000)
n	75	75	75	75
Condition No.	2.16		5.09	
Mean VIF	1.00		3.05	
BP, standard	0.429		0.700	
BP, N*R2	0.832		0.936	
BP, F-stat	0.835		0.937	
White's test	0.506		0.980	
DW value	1.08		1.13	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-1.37	-1.42	0.71	0.77
RESET test	0.056		0.526	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table V-F3: Panel B: OLS: *nysi* to *onzn*: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	-0.810 (0.758)	-0.810 (0.548)	-0.391 (0.785)	-0.391 (0.678)
HDD PosDev onzn	-0.986 (1.092)	-0.986 (0.826)	-0.155 (0.883)	-0.155 (0.384)
HDD NegDev onzn	-2.135 (4.789)	-2.135 (2.990)	-2.732 (4.278)	-2.732 (3.349)
CDD PosDev onzn	6.239 (6.540)	6.239 (6.691)	7.856 (5.180)	7.856 (6.412)
CDD NegDev onzn	-7.277 (10.457)	-7.277 (5.962)	-1.780 (8.340)	-1.780 (3.247)
HDD PosDev nysi	-3.240 (4.702)	-3.240 (3.056)	-0.115 (4.058)	-0.115 (1.636)
HDD NegDev nysi	3.548 (7.163)	3.548 (4.062)	4.296 (6.215)	4.296 (4.256)
CDD PosDev nysi	15.907 (8.112)*	15.907 (12.782)	15.903 (6.405)**	15.903 (12.547)
CDD NegDev nysi	0.548 (3.693)	0.548 (3.373)	2.778 (7.659)	2.778 (2.364)
Natural gas price	-358.190 (800.644)	-358.190 (694.011)	-439.016 (658.612)	-439.016 (371.593)
Natural gas capacity ratio	-10132.464 (9622.936)	-10132.464 (11010.653)	-5834.842 (7858.920)	-5834.842 (5883.376)
NG price * NG capacity ratio	769.831 (1758.859)	769.831 (1466.871)	1146.151 (1470.874)	1146.151 (850.560)
Risk-free	-206.878 (118.696)*	-206.878 (140.230)	-101.584 (96.757)	-101.584 (102.530)
1 / t			5674.202 (1064.636)****	5674.202 (431.919)****
MCP / t			-8.620 (4.938)*	-8.620 (2.615)***
Constant	5503.945 (4714.820)	5503.945 (5788.715)	2316.903 (3834.291)	2316.903 (2910.809)
R-square	0.224		0.532	
Adj. R-square	0.058		0.413	
AIC	1225.019		1191.027	
BIC	1257.464		1228.107	

Root MSE	784.070		618.863	
Overall F-stat	1.351 (0.210)	0.590 (0.853)	4.474 (0.000)	142.090 (0.000)
n	75	75	75	75
Condition No.	283.16		303.78	
Mean VIF	41.68		40.52	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.019	
BP, F-stat	0.000		0.018	
White's test	0.446		0.446	
DW value	1.40		1.73	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	3.10	1.68	0.75	0.35
RESET test	0.001		0.036	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F3: Panel C: OLS: *nysi* to *onzn*: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	-0.215 (0.511)	-0.215 (0.272)	0.692 (0.724)	0.692 (0.490)
Lag of Profit	0.274 (0.091)***	0.274 (0.176)	0.333 (0.098)***	0.333 (0.185)*
1 / t			2735.048 (4057.118)	2735.048 (3200.526)
MCP / t			-10.497 (8.822)	-10.497 (9.041)
Constant	159.330 (103.943)	159.330 (93.604)*	42.542 (152.392)	42.542 (64.138)
R-square	0.124		0.165	
Adj. R-square	0.097		0.112	
AIC	1076.142		1076.836	
BIC	1082.801		1087.934	
Root MSE	646.981		641.387	
Overall F-stat	4.587 (0.014)	1.733 (0.185)	3.118 (0.021)	1.035 (0.396)
n	68	68	68	68
Condition No.	2.20		11.98	
Mean VIF	1.00		9.63	
BP, standard	0.000		0.000	
BP, N*R2	0.011		0.006	
BP, F-stat	0.010		0.005	
White's test	0.000		0.000	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-2.23	-1.02	-0.41	-0.22
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F3: Panel D: OLS: *nysi* to *onzn*: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	-0.352 (0.689)	-0.352 (0.424)	-0.029 (1.236)	-0.029 (0.658)
HDD PosDev onzn	-0.292 (0.893)	-0.292 (0.349)	-0.409 (0.932)	-0.409 (0.349)
HDD NegDev onzn	-3.529 (4.244)	-3.529 (3.743)	-2.669 (4.601)	-2.669 (3.824)
CDD PosDev onzn	10.055 (5.550)*	10.055 (6.273)	10.651 (5.751)*	10.651 (6.134)*
CDD NegDev onzn	-0.880 (10.273)	-0.880 (2.518)	-1.105 (10.608)	-1.105 (2.557)
HDD PosDev nysi	-0.392 (4.095)	-0.392 (0.944)	0.533 (5.118)	0.533 (1.619)
HDD NegDev nysi	5.180 (6.329)	5.180 (4.854)	4.123 (6.784)	4.123 (5.014)
CDD PosDev nysi	10.268 (7.706)	10.268 (11.340)	8.432 (8.504)	8.432 (12.288)
CDD NegDev nysi	0.089 (9.109)	0.089 (2.332)	-0.679 (9.362)	-0.679 (2.424)
Natural gas price	-239.077 (727.714)	-239.077 (460.127)	-116.890 (876.662)	-116.890 (584.902)
Natural gas capacity ratio	-5229.385 (8592.816)	-5229.385 (6730.633)	-4310.037 (9206.556)	-4310.037 (7479.620)
NG price * NG capacity ratio	640.718 (1599.157)	640.718 (1018.368)	303.011 (1955.806)	303.011 (1310.481)
Risk-free	-121.322 (102.366)	-121.322 (94.616)	-118.597 (108.263)	-118.597 (93.020)
Lag of Profit	0.162 (0.115)	0.162 (0.121)	0.213 (0.149)	0.213 (0.173)
1 / t			-742.481 (7364.032)	-742.481 (3027.629)
MCP / t			-1.291 (15.143)	-1.291 (5.623)
Constant	2474.579 (4216.036)	2474.579 (3354.369)	2246.307 (4380.629)	2246.307 (3607.100)
R-square	0.323		0.327	
Adj. R-square	0.144		0.116	

AIC	1082.581		1086.173	
BIC	1115.874		1123.904	
Root MSE	629.697		639.999	
Overall F-stat	1.807 (0.062)	0.469 (0.940)	1.550 (0.119)	0.477 (0.947)
n	68	68	68	68
Condition No.	303.84		303.78	
Mean VIF	43.14		40.52	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.443		0.443	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	1.25	0.86	0.83	0.54
RESET test	0.000		0.000	

Point estimates from OLS and Newey-West estimation approaches are the same.

Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are unnormalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F4: Panel A: OLS: nysi to onzn: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	3.0 (0.086)	3.3 (0.075)	0.0 (0.988)	0.0 (0.986)
Hypothesis B	0.1 (0.792)	0.8 (0.362)	0.0 (0.832)	0.8 (0.389)
Hypothesis C	3.9 (0.053)	46.8 (0.000)	2.0 (0.167)	32.3 (0.000)
Hypothesis D	2.1 (0.126)	28.3 (0.000)	1.6 (0.200)	16.1 (0.000)
Hypothesis E			32.9 (0.000)	346.7 (0.000)
Hypothesis F			9.8 (0.002)	70.0 (0.000)
Hypothesis G			19.5 (0.000)	340.3 (0.000)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F4: Panel B: OLS: nysi to onzn: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	1.4 (0.248)	0.9 (0.345)	0.4 (0.548)	0.6 (0.429)
Hypothesis B	1.1 (0.290)	2.2 (0.145)	0.2 (0.620)	0.3 (0.567)
Hypothesis C	5.7 (0.020)	10.9 (0.002)	3.1 (0.082)	4.2 (0.045)
Hypothesis D	3.8 (0.027)	5.8 (0.005)	1.7 (0.194)	2.2 (0.121)
Hypothesis E			28.4 (0.000)	172.6 (0.000)
Hypothesis F			3.0 (0.086)	10.9 (0.002)
Hypothesis G			19.5 (0.000)	222.3 (0.000)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F4: Panel C: OLS: nysi to onzn: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	2.3 (0.130)	2.9 (0.094)	0.1 (0.781)	0.4 (0.510)
Hypothesis B	0.2 (0.675)	0.6 (0.432)	0.9 (0.343)	2.0 (0.163)
Hypothesis C	5.6 (0.020)	20.0 (0.000)	0.2 (0.672)	0.4 (0.532)
Hypothesis D	2.8 (0.067)	11.1 (0.000)	0.1 (0.912)	0.3 (0.733)
Hypothesis E			0.5 (0.503)	0.7 (0.396)
Hypothesis F			1.4 (0.239)	1.3 (0.250)
Hypothesis G			1.6 (0.216)	1.1 (0.336)
Hypothesis J	9.1 (0.004)	2.4 (0.125)	11.6 (0.001)	3.3 (0.076)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F4: Panel D: OLS: nysi to onzn: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	0.3 (0.560)	0.5 (0.464)	0.3 (0.610)	0.4 (0.536)
Hypothesis B	0.3 (0.612)	0.7 (0.411)	0.0 (0.982)	0.0 (0.965)
Hypothesis C	3.8 (0.055)	10.2 (0.002)	0.7 (0.409)	2.4 (0.124)
Hypothesis D	2.3 (0.107)	5.1 (0.009)	0.6 (0.572)	1.4 (0.265)
Hypothesis E			0.0 (0.920)	0.1 (0.807)
Hypothesis F			0.2 (0.932)	0.1 (0.819)
Hypothesis G			0.2 (0.858)	0.3 (0.715)
Hypothesis J	2.0 (0.164)	1.8 (0.184)	2.0 (0.160)	1.5 (0.225)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F5: Panel A: OLS: onzn to misi: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	0.491 (0.095)****	0.491 (0.052)****	0.750 (0.293)**	0.750 (0.130)****
1 / t			-519.653 (702.830)	-519.653 (312.061)
MCP / t			-15.885 (16.257)	-15.885 (6.460)**
Constant	225.393 (98.471)**	225.393 (96.938)**	283.619 (111.073)**	283.619 (117.390)**
R-square	0.270		0.288	
Adj. R-square	0.260		0.257	
AIC	1198.858		1201.016	
BIC	1203.466		1210.232	
Root MSE	786.920		788.211	
Overall F-stat	26.634 (0.000)	89.627 (0.000)	9.437 (0.000)	32.337 (0.000)
n	74	74	74	74
Condition No.	1.47		7.02	
Mean VIF	1.00		6.61	
BP, standard	0.758		0.713	
BP, N*R2	0.920		0.904	
BP, F-stat	0.921		0.906	
White's test	0.920		0.982	
DW value	1.44		1.48	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-0.26	-0.27	-0.02	-0.03
RESET test	0.942		0.712	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F5: Panel B: OLS: onzn to misi: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	0.419 (0.115)****	0.419 (0.085)****	0.796 (0.381)**	0.796 (0.205)****
HDD PosDev onzn	-0.021 (1.106)	-0.021 (0.694)	-0.339 (1.148)	-0.339 (0.774)
HDD NegDev onzn	3.727 (4.651)	3.727 (7.989)	4.033 (4.679)	4.033 (7.983)
CDD PosDev onzn	2.681 (9.798)	2.681 (5.669)	3.087 (9.846)	3.087 (5.531)
CDD NegDev onzn	-5.699 (17.203)	-5.699 (13.035)	-0.574 (18.361)	-0.574 (14.141)
HDD PosDev misi	-2.231 (4.510)	-2.231 (4.286)	-2.425 (4.530)	-2.425 (4.333)
HDD NegDev misi	-4.717 (6.628)	-4.717 (7.303)	-5.016 (6.658)	-5.016 (7.277)
CDD PosDev misi	-8.579 (12.613)	-8.579 (3.874)**	-9.477 (12.709)	-9.477 (4.198)**
CDD NegDev misi	13.252 (17.571)	13.252 (19.708)	10.765 (17.764)	10.765 (18.905)
Natural gas price	-1290.331 (849.400)	-1290.331 (1015.525)	-1181.111 (857.732)	-1181.111 (1014.889)
Natural gas capacity ratio	-14797.924 (10115.441)	-14797.924 (12086.973)	-15317.455 (10167.158)	-15317.455 (12718.997)
NG price * NG capacity ratio	2896.291 (1895.308)	2896.291 (2226.055)	2607.895 (1920.520)	2607.895 (2212.891)
Risk-free	-143.180 (112.121)	-143.180 (138.689)	-166.863 (115.214)	-166.863 (148.447)
1 / t			-698.021 (925.986)	-698.021 (670.537)
MCP / t			-22.951 (22.259)	-22.951 (13.054)*
Constant	7331.079 (4891.814)	7331.079 (6239.010)	7835.772 (4941.598)	7835.772 (6635.746)
R-square	0.361		0.377	
Adj. R-square	0.222		0.216	
AIC	1213.041		1215.083	
BIC	1245.298		1251.948	

Root MSE	806.705		809.711	
Overall F-stat	2.604 (0.006)	13.315 (0.000)	2.344 (0.011)	9.722 (0.000)
n	74	74	74	74
Condition No.	286.35		295.77	
Mean VIF	45.004		41.76	
BP, standard	0.002		0.000	
BP, N*R2	0.298		0.222	
BP, F-stat	0.304		0.228	
White's test	0.445		0.445	
DW value	1.58		1.64	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	0.64	0.68	0.71	0.72
RESET test	0.630		0.451	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F5: Panel C: OLS: onzn to misi: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	0.481 (0.141)***	0.481 (0.091)****	0.684 (0.324)**	0.684 (0.132)****
Lag of Profit	0.126 (0.135)	0.126 (0.126)	0.108 (0.136)	0.108 (0.126)
1 / t			-1257.409 (1351.580)	-1257.409 (710.002)
MCP / t			-13.916 (17.506)	-13.916 (5.698)
Constant	242.706 (111.305)**	242.706 (107.937)**	338.392 (136.121)**	338.392 (145.871)**
R-square	0.157		0.186	
Adj. R-square	0.130		0.129	
AIC	1077.486		1079.462	
BIC	1084.055		1090.462	
Root MSE	830.180		830.838	
Overall F-stat	5.876 (0.005)	34.304 (0.000)	3.408 (0.014)	17.609 (0.000)
n	66	66	66	66
Condition No.	1.70		5.74	
Mean VIF	1.11		3.47	
BP, standard	0.539		0.611	
BP, N*R2	0.837		0.863	
BP, F-stat	0.840		0.866	
White's test	0.963			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-0.08	-0.11	0.14	0.29
RESET test	0.604		0.668	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F5: Panel D: OLS: onzn to misi: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	0.310 (0.177)*	0.310 (0.129)**	1.000 (0.465)***	1.000 (0.240)****
HDD PosDev onzn	-0.174 (1.180)	-0.174 (0.819)	-0.795 (1.228)	-0.795 (0.893)
HDD NegDev onzn	1.714 (5.174)	1.714 (9.496)	3.134 (5.229)	3.134 (9.656)
CDD PosDev onzn	-0.625 (10.701)	-0.625 (7.057)	0.663 (10.617)	0.663 (6.708)
CDD NegDev onzn	3.400 (21.292)	3.400 (16.420)	29.927 (27.373)	29.927 (14.986)*
HDD PosDev misi	-0.341 (5.393)	-0.341 (3.715)	-0.228 (5.374)	-0.228 (3.733)
HDD NegDev misi	-1.857 (7.596)	-1.857 (9.033)	-3.852 (7.596)	-3.852 (9.249)
CDD PosDev misi	-6.688 (14.133)	-6.688 (4.120)	-8.683 (14.021)	-8.683 (4.682)*
CDD NegDev misi	5.752 (20.241)	5.752 (21.093)	-8.657 (21.807)	-8.657 (19.426)
Natural gas price	-1960.196 (978.785)*	-1960.196 (1236.642)	-1315.701 (1056.278)	-1315.701 (1229.378)
Natural gas capacity ratio	-22353.805 (11603.800)*	-22353.805 (14608.735)	-18343.128 (11741.724)	-18343.128 (14409.611)
NG price * NG capacity ratio	4326.347 (2168.678)*	4326.347 (2697.768)	2812.999 (2370.503)	2812.999 (2713.408)
Risk-free	-217.497 (128.873)*	-217.497 (177.385)	-250.042 (130.635)*	-250.042 (178.120)
Lag of Profit	0.089 (0.146)	0.089 (0.127)	0.023 (0.151)	0.023 (0.115)
1 / t			-2070.307 (2069.981)	-2070.307 (1895.330)
MCP / t			-50.220 (31.235)	-50.220 (17.902)***
Constant	11246.374 (5665.362)*	11246.374 (7614.674)	9894.621 (5656.356)*	9894.621 (7467.092)
R-square	0.293		0.336	
Adj. R-square	0.099		0.119	

AIC	1089.910		1089.754	
BIC	1122.755		1126.977	
Root MSE	845.755		835.561	
Overall F-stat	1.508 (0.142)	9.736 (0.000)	1.550 (0.120)	14.046 (0.000)
n	66	66	66	66
Condition No.	286.35		295.77	
Mean VIF	45.04		41.76	
BP, standard	0.000		0.000	
BP, N*R2	0.161		0.103	
BP, F-stat	0.166		0.107	
White's test	0.442			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	0.75	0.97	0.87	1.05
RESET test	0.179		0.354	

Point estimates from OLS and Newey-West estimation approaches are the same.

Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are unnormalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F6: Panel A: OLS: onzn to misi: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	5.2 (0.025)	5.4 (0.023)	6.5 (0.013)	5.8 (0.018)
Hypothesis B	26.6 (0.000)	89.6 (0.000)	6.6 (0.013)	33.5 (0.000)
Hypothesis C	28.7 (0.000)	96.5 (0.000)	0.7 (0.396)	3.7 (0.058)
Hypothesis D	14.4 (0.000)	48.3 (0.000)	3.6 (0.032)	8.5 (0.000)
Hypothesis E			0.5 (0.462)	2.8 (0.100)
Hypothesis F			1.0 (0.332)	6.0 (0.016)
Hypothesis G			0.9 (0.418)	3.4 (0.040)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F6: Panel B: OLS: onzn to misi: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	2.2 (0.139)	1.4 (0.245)	2.5 (0.118)	1.4 (0.242)
Hypothesis B	13.2 (0.001)	24.2 (0.000)	4.4 (0.041)	15.0 (0.000)
Hypothesis C	25.5 (0.000)	46.7 (0.000)	0.3 (0.594)	1.0 (0.324)
Hypothesis D	12.8 (0.000)	33.4 (0.000)	1.4 (0.263)	1.1 (0.340)
Hypothesis E			0.6 (0.454)	1.1 (0.302)
Hypothesis F			1.1 (0.307)	3.1 (0.084)
Hypothesis G			0.8 (0.464)	1.8 (0.178)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F6: Panel C: OLS: onzn to misi: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	4.8 (0.033)	5.1 (0.028)	6.2 (0.016)	5.4 (0.024)
Hypothesis B	11.7 (0.001)	28.1 (0.000)	4.5 (0.039)	27.0 (0.000)
Hypothesis C	13.6 (0.000)	32.6 (0.000)	0.9 (0.335)	5.7 (0.020)
Hypothesis D	7.1 (0.002)	16.3 (0.000)	3.3 (0.042)	6.5 (0.003)
Hypothesis E			0.9 (0.356)	3.1 (0.082)
Hypothesis F			0.6 (0.430)	6.0 (0.018)
Hypothesis G			1.0 (0.392)	3.4 (0.040)
Hypothesis J	0.9 (0.354)	1.0 (0.320)	0.6 (0.428)	0.7 (0.394)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F6: Panel D: OLS: onzn to misi: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	3.9 (0.053)	2.2 (0.146)	3.1 (0.087)	1.8 (0.191)
Hypothesis B	2.9 (0.094)	5.4 (0.024)	4.6 (0.037)	17.3 (0.000)
Hypothesis C	15.6 (0.000)	29.1 (0.000)	0.0 (1.000)	0.0 (0.999)
Hypothesis D	8.7 (0.001)	19.2 (0.000)	1.6 (0.218)	1.0 (0.375)
Hypothesis E			1.0 (0.322)	1.2 (0.280)
Hypothesis F			2.6 (0.114)	7.9 (0.007)
Hypothesis G			1.6 (0.214)	5.7 (0.006)
Hypothesis J	0.4 (0.544)	0.5 (0.487)	0.0 (0.878)	0.0 (0.841)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F7: Panel A: OLS: onzn to nysi: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	0.649 (0.203)***	0.649 (0.139)****	0.703 (0.256)***	0.703 (0.148)****
1 / t			-438.055 (1955.385)	-438.055 (809.413)
MCP / t			-4.601 (7.764)	-4.601 (4.422)
Constant	476.397 (269.397)*	476.397 (224.697)**	614.319 (306.448)**	614.319 (259.547)**
R-square	0.126		0.139	
Adj. R-square	0.114		0.101	
AIC	1290.000		1292.937	
BIC	1294.581		1302.099	
Root MSE	1641.180		1652.722	
Overall F-stat	10.239 (0.002)	21.787 (0.000)	3.703 (0.016)	14.443 (0.000)
n	73	73	73	73
Condition No.	2.39		4.32	
Mean VIF	1.00		1.82	
BP, standard	0.107		0.123	
BP, N*R2	0.607		0.630	
BP, F-stat	0.613		0.636	
White's test	0.486		0.935	
DW value	1.62		1.63	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	0.27	0.28	0.21	0.29
RESET test	0.643		0.908	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F7: Panel B: OLS: onzn to nysi: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	0.211 (0.214)	0.211 (0.206)	0.285 (0.298)	0.285 (0.235)
HDD PosDev onzn	-1.636 (2.081)	-1.636 (1.002)	-1.331 (2.150)	-1.331 (0.926)
HDD NegDev onzn	-13.354 (9.191)	-13.354 (7.402)*	-14.210 (9.808)	-14.210 (7.356)*
CDD PosDev onzn	-16.152 (12.613)	-16.152 (8.091)*	-15.436 (12.762)	-15.436 (8.001)*
CDD NegDev onzn	-8.285 (20.028)	-8.285 (17.189)	-4.562 (20.797)	-4.562 (17.287)
HDD PosDev nysi	-9.509 (8.976)	-9.509 (8.174)	-8.451 (9.658)	-8.451 (8.139)
HDD NegDev nysi	4.192 (13.532)	4.192 (10.175)	5.467 (14.127)	5.467 (9.826)
CDD PosDev nysi	8.017 (15.505)	8.017 (7.513)	8.229 (15.642)	8.229 (7.972)
CDD NegDev nysi	45.601 (18.635)**	45.601 (20.107)**	45.958 (18.875)**	45.958 (20.247)**
Natural gas price	-2372.086 (1589.839)	-2372.086 (1592.589)	-2349.463 (1753.692)	-2349.463 (1481.671)
Natural gas capacity ratio	-25430.877 (19305.586)	-25430.877 (18808.688)	-23553.518 (20327.113)	-23553.518 (18090.679)
NG price * NG capacity ratio	6454.685 (3552.692)*	6454.685 (3269.410)*	6519.532 (3923.101)	6519.532 (3084.733)**
Risk-free	-157.669 (226.177)	-157.669 (206.693)	-125.464 (230.363)	-125.464 (204.288)
1 / t			1960.351 (1997.680)	1960.351 (1457.878)
MCP / t			-2.976 (9.856)	-2.976 (7.605)
Constant	9904.748 (9417.637)	9904.748 (10014.587)	8496.298 (9913.122)	8496.298 (9850.278)
R-square	0.408		0.418	
Adj. R-square	0.278		0.265	
AIC	1285.544		1288.261	
BIC	1317.610		1324.909	

Root MSE	1481.536		1494.124	
Overall F-stat	3.130 (0.001)	5.680 (0.000)	2.735 (0.003)	5.347 (0.000)
n	73	73	73	73
Condition No.	294.89		332.87	
Mean VIF	42.57		43.99	
BP, standard	0.000		0.000	
BP, N*R2	0.001		0.001	
BP, F-stat	0.001		0.000	
White's test	0.445		0.445	
DW value	1.84		1.88	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	3.81	2.53	3.62	2.32
RESET test	0.000		0.001	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number), Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F7: Panel C: OLS: onzn to nysi: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	0.308 (0.244)	0.308 (0.125)**	0.302 (0.326)	0.302 (0.172)
Lag of Profit	0.261 (0.129)**	0.261 (0.198)	0.263 (0.130)**	0.263 (0.195)
1 / t			-1759.650 (4183.232)	-1759.650 (1802.892)
MCP / t			-1.582 (9.838)	-1.582 (5.186)
Constant	647.340 (291.935)**	647.340 (242.017)***	800.118 (346.365)**	800.118 (292.913)***
R-square	0.131		0.142	
Adj. R-square	0.103		0.086	
AIC	1165.791		1168.942	
BIC	1172.360		1179.890	
Root MSE	1620.710		1636.498	
Overall F-stat	4.745 (0.012)	9.141 (0.000)	2.525 (0.050)	16.803 (0.000)
n	66	66	66	66
Condition No.	2.80		5.84	
Mean VIF	1.21		2.27	
BP, standard	0.000		0.000	
BP, N*R2	0.052		0.061	
BP, F-stat	0.053		0.063	
White's test	0.084			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-3.61	-2.37	-2.62	-1.72
RESET test	0.003		0.005	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F7: Panel D: OLS: onzn to nysi: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	0.091 (0.244)	0.091 (0.176)	0.212 (0.328)	0.212 (0.219)
HDD PosDev onzn	-1.054 (2.115)	-1.054 (0.895)	-0.610 (2.143)	-0.610 (0.835)
HDD NegDev onzn	-8.830 (9.546)	-8.830 (6.323)	-17.794 (10.954)	-17.794 (8.070)**
CDD PosDev onzn	-15.330 (12.982)	-15.330 (8.271)*	-16.564 (12.901)	-16.564 (8.744)*
CDD NegDev onzn	-18.557 (24.221)	-18.557 (19.751)	-10.283 (26.048)	-10.283 (21.814)
HDD PosDev nysi	-9.791 (9.664)	-9.791 (9.082)	-12.173 (10.206)	-12.173 (8.720)
HDD NegDev nysi	-0.218 (14.137)	-0.218 (10.096)	12.024 (15.798)	12.024 (10.280)
CDD PosDev nysi	11.188 (15.574)	11.188 (7.427)	11.496 (15.425)	11.496 (8.583)
CDD NegDev nysi	57.972 (21.431)***	57.972 (22.381)**	59.345 (21.891)***	59.345 (22.432)**
Natural gas price	-1242.190 (1757.797)	-1242.190 (1438.834)	-2608.192 (2017.714)	-2608.192 (1371.500)*
Natural gas capacity ratio	-11208.229 (21347.152)	-11208.229 (16975.330)	-22120.487 (22666.172)	-22120.487 (15875.694)
NG price * NG capacity ratio	3944.359 (3924.518)	3944.359 (2815.099)	7262.439 (4561.908)	7262.439 (3058.492)**
Risk-free	9.608 (247.565)	9.608 (169.695)	9.029 (245.334)	9.029 (178.180)
Lag of Profit	0.058 (0.131)	0.058 (0.216)	0.030 (0.130)	0.030 (0.214)
1 / t			8186.257 (4931.794)	8186.257 (4043.866)**
MCP / t			-5.462 (11.063)	-5.462 (7.717)
Constant	2749.048 (10468.587)	2749.048 (9561.419)	6703.614 (10884.444)	6703.614 (8772.796)
R-square	0.418		0.452	
Adj. R-square	0.259		0.273	

AIC	1163.274		1163.352	
BIC	1196.119		1200.576	
Root MSE	1473.483		1459.245	
Overall F-stat	2.621 (0.006)	5.909 (0.000)	2.526 (0.007)	8.639 (0.000)
n	66	66	66	66
Condition No.	294.89		332.87	
Mean VIF	42.57		43.99	
BP, standard	0.000		0.000	
BP, N*R2	0.001		0.001	
BP, F-stat	0.000		0.000	
White's test	0.442			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	3.22	2.42	3.77	2.49
RESET test	0.000		0.000	

Point estimates from OLS and Newey-West estimation approaches are the same.

Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (Number) and Mean VIF the reported values are unnormalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-F8: Panel A: OLS: onzn to nysi: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	3.1 (0.081)	4.5 (0.037)	4.0 (0.049)	5.6 (0.021)
Hypothesis B	10.2 (0.002)	21.8 (0.000)	7.6 (0.008)	22.5 (0.000)
Hypothesis C	3.0 (0.088)	6.3 (0.014)	1.3 (0.250)	4.0 (0.049)
Hypothesis D	1.8 (0.173)	3.8 (0.026)	2.0 (0.138)	3.3 (0.043)
Hypothesis E			0.1 (0.823)	0.3 (0.590)
Hypothesis F			0.4 (0.555)	1.1 (0.302)
Hypothesis G			0.5 (0.605)	3.5 (0.034)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F8: Panel B: OLS: onzn to nysi: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	1.1 (0.297)	1.0 (0.327)	0.7 (0.395)	0.7 (0.392)
Hypothesis B	1.0 (0.327)	1.1 (0.309)	0.9 (0.343)	1.5 (0.230)
Hypothesis C	13.6 (0.000)	14.6 (0.000)	5.7 (0.020)	9.3 (0.004)
Hypothesis D	6.8 (0.002)	7.3 (0.001)	2.9 (0.064)	4.7 (0.013)
Hypothesis E			1.0 (0.331)	1.8 (0.184)
Hypothesis F			0.1 (0.763)	0.2 (0.697)
Hypothesis G			0.5 (0.606)	0.9 (0.408)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F8: Panel C: OLS: onzn to nysi: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	4.9 (0.030)	7.2 (0.010)	5.3 (0.024)	7.5 (0.008)
Hypothesis B	1.6 (0.212)	6.1 (0.016)	0.9 (0.359)	3.1 (0.085)
Hypothesis C	8.0 (0.006)	30.7 (0.000)	4.6 (0.036)	16.5 (0.000)
Hypothesis D	4.0 (0.022)	17.5 (0.000)	3.1 (0.051)	8.3 (0.001)
Hypothesis E			0.2 (0.675)	1.0 (0.333)
Hypothesis F			0.0 (0.873)	0.1 (0.761)
Hypothesis G			0.4 (0.675)	3.3 (0.042)
Hypothesis J	4.1 (0.047)	1.7 (0.191)	4.1 (0.048)	1.8 (0.182)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F8: Panel D: OLS: onzn to nysi: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	0.1 (0.794)	0.1 (0.775)	0.4 (0.541)	0.6 (0.448)
Hypothesis B	0.1 (0.712)	0.3 (0.610)	0.4 (0.521)	0.9 (0.338)
Hypothesis C	13.9 (0.000)	26.6 (0.000)	5.8 (0.020)	12.9 (0.001)
Hypothesis D	7.2 (0.002)	18.0 (0.000)	2.9 (0.065)	6.9 (0.002)
Hypothesis E			2.8 (0.103)	4.1 (0.048)
Hypothesis F			0.2 (0.624)	0.5 (0.482)
Hypothesis G			1.5 (0.233)	2.2 (0.127)
Hypothesis J	0.2 (0.660)	0.1 (0.791)	0.1 (0.820)	0.0 (0.890)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-F9: Panel A: SUR estimates for configuration (I)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	1.143 (0.227)****	-0.096 (0.644)	0.548 (0.240)**	0.720 (0.199)****
Constant	59.763 (205.679)	213.700 (126.003)*	213.797 (108.338)	422.216 (265.007)
R-square	0.282		AIC	4843.854
Chi2-stat.	25.380 (0.000)		BIC	4862.067
n	72		Root MSE	1288.164

Note: SUR standard errors are in parentheses.

Table V-F9: Panel B: SUR estimates for configuration (II)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.575 (0.268)**	0.597 (0.714)	0.794 (0.350)**	0.744 (0.247)***
1 / t	-4041.374 (2097.376)*	5789.949 (1014.633)****	-502.549 (697.150)	-582.638 (1901.316)
MCP / t	8.903 (3.064)***	-13.152 (4.161)***	-17.912 (15.981)	-3.353 (7.507)
Constant	175.180 (205.048)	-44.265 (111.289)	283.515 (122.230)**	554.496 (296.156)*
R-square	0.342		AIC	4807.741
Chi2-stat.	36.062 (0.000)		BIC	4844.168
n	72		Root MSE	1233.670

Note: SUR standard errors are in parentheses.

Table V-F9: Panel C: SUR estimates for configuration (III)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.632 (0.318)**	-0.688 (0.793)	0.076 (0.296)	0.236 (0.195)
HDD PosDev onzn	-2.510 (1.393)*	-1.097 (1.001)	-0.044 (0.995)	-1.642 (1.883)
HDD NegDev onzn	2.443 (5.697)	-2.914 (4.446)	3.352 (4.188)	-13.287 (8.301)
CDD PosDev onzn	-13.028 (12.079)	6.119 (6.072)	1.710 (8.811)	-15.525 (11.505)
CDD NegDev onzn	-62.570 (22.555)***	-8.069 (9.565)	-5.420 (16.695)	-8.086 (18.113)
HDD PosDev external	11.573 (5.565)**	-5.587 (4.311)	-2.004 (4.051)	-11.127 (8.120)
HDD NegDev external	-9.462 (8.193)	3.722 (6.534)	-4.454 (5.959)	3.572 (12.224)
CDD PosDev external	46.527 (15.867)***	14.076 (7.594)*	-7.416 (11.335)	5.665 (14.468)
CDD NegDev external	34.541 (22.511)	-0.947 (8.809)	17.262 (17.399)	43.560 (16.836)***
Natural gas price	3046.813 (1133.642)***	-432.046 (765.612)	-1490.009 (774.619)*	-2332.899 (1438.090)
Natural gas capacity ratio	26134.763 (12917.465)**	-10885.674 (9061.056)	-16550.225 (9164.374)*	-24962.690 (17461.977)
NG price * NG capacity ratio	-6303.402 (2476.681)**	918.670 (1693.003)	3286.423 (1722.654)*	6352.698 (3212.946)**
Risk-free	-290.670 (139.282)**	-203.025 (109.095)*	-155.211 (101.728)	-151.531 (206.179)
Constant	-12549.301 (6280.096)**	5955.183 (4406.986)	8385.713 (4450.731)*	9740.071 (8520.379)
R-square	0.564		AIC	4851.991
Chi2-stat.	90.454 (0.000)		BIC	4979.485
n	72		Root MSE	1004.510

Note: SUR standard errors are in parentheses.

Table V-F9: Panel D: SUR estimates for configuration (IV)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	-0.041 (0.353)	0.322 (0.806)	0.518 (0.414)	0.289 (0.266)
1 / t	-3576.687 (1757.671)**	5795.905 (967.580)****	-839.874 (814.663)	1994.442 (1780.912)
MCP / t	9.458 (2.939)***	-9.945 (4.489)**	-31.306 (19.999)	-3.380 (8.742)
HDD PosDev onzn	-1.585 (1.359)	-0.328 (0.796)	-0.465 (1.008)	-1.351 (1.913)
HDD NegDev onzn	-3.406 (5.486)	-3.038 (3.786)	3.453 (4.102)	-14.235 (8.720)
CDD PosDev onzn	-14.027 (11.301)	7.956 (4.701)*	2.845 (8.626)	-15.983 (11.456)
CDD NegDev onzn	-61.518 (21.114)***	-1.785 (7.467)	2.096 (17.496)	-4.303 (18.511)
HDD PosDev external	6.210 (5.437)	-2.276 (3.600)	-2.314 (3.963)	-7.799 (8.595)
HDD NegDev external	-1.584 (7.806)	3.471 (5.455)	-4.470 (5.830)	5.662 (12.571)
CDD PosDev external	49.746 (14.873)****	13.158 (5.828)**	-9.705 (11.125)	9.897 (14.376)
CDD NegDev external	40.143 (20.989)*	0.900 (6.771)	14.612 (17.128)	46.142 (16.800)***
Natural gas price	2158.612 (1093.077)**	-593.042 (607.986)	-1416.505 (760.019)*	-2345.378 (1559.354)
Natural gas capacity ratio	19501.693 (12287.943)	-6933.485 (7166.420)	-17861.233 (8986.889)**	-23619.275 (18079.207)
NG price * NG capacity ratio	-3954.662 (2419.734)	1474.883 (1360.656)	3057.233 (1695.827)*	6505.354 (3488.013)*
Risk-free	-237.120 (133.917)*	-90.377 (86.617)	-187.619 (102.178)*	-125.240 (206.266)
Constant	-10545.517 (5963.517)*	5955.183 (4406.986)	9370.860 (4392.583)**	8534.902 (8820.904)
R-square	0.614		AIC	4814.521
Chi2-stat.	111.705 (0.000)		BIC	4960.227
n	72		Root MSE	944.500

Note: SUR standard errors are in parentheses.

Table V-F9: Panel E: SUR estimates for configuration (V)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.922 (0.237)****	-0.253 (0.522)	0.556 (0.271)**	0.335 (0.244)
Lag of Profit	0.417 (0.111)****	0.203 (0.088)**	0.100 (0.162)	0.248 (0.128)*
Constant	163.331 (215.765)	173.831 (106.327)	229.750 (118.966)*	628.836 (290.224)**
R-square	0.392		AIC	4286.477
Chi2-stat.	38.448 (0.000)		BIC	4312.383
n	64		Root MSE	1242.541

Note: SUR standard errors are in parentheses.

Table V-F9: Panel F: SUR estimates for configuration (VI)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.157 (0.303)	0.938 (0.746)	0.727 (0.391)*	0.331 (0.320)
1 / t	-19980.882 (6972.271)***	1521.908 (3940.745)	-1235.927 (1333.728)	-1788.888 (4080.211)
MCP / t	21.506 (6.270)****	-8.001 (8.583)	-15.366 (17.030)	-1.411 (9.595)
Lag of Profit	0.396 (0.098)****	0.240 (0.091)***	0.088 (0.160)	0.251 (0.128)*
Constant	591.300 (256.748)**	52.171 (152.638)	338.612 (144.512)**	776.671 (339.470)
R-square	0.506		AIC	4279.512
Chi2-stat.	64.803 (0.000)		BIC	4322.383
n	64		Root MSE	1120.637

Note: SUR standard errors are in parentheses.

Table V-F9: Panel G: SUR estimates for configuration (VII)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.692 (0.339)**	-0.347 (0.658)	0.061 (0.328)	0.095 (0.220)
HDD PosDev onzn	-2.267 (1.423)	-0.338 (0.808)	-0.275 (1.047)	-1.083 (1.884)
HDD NegDev onzn	-1.785 (6.180)	-2.538 (3.931)	1.237 (4.603)	-8.869 (8.512)
CDD PosDev onzn	-12.922 (12.584)	8.969 (5.187)*	-0.482 (9.465)	-14.104 (11.771)
CDD NegDev onzn	-29.705 (27.336)	-2.117 (9.201)	-2.962 (19.827)	-17.143 (21.575)
HDD PosDev external	17.370 (6.523)***	-2.435 (3.689)	-0.539 (4.791)	-10.807 (8.619)
HDD NegDev external	-2.906 (9.107)	3.472 (5.711)	-1.614 (6.722)	-1.510 (12.589)
CDD PosDev external	42.124 (17.150)**	13.164 (8.025)	-7.744 (12.532)	6.095 (15.763)
CDD NegDev external	12.383 (25.469)	0.393 (8.175)	13.723 (19.480)	56.086 (19.088)***
Natural gas price	1886.747 (1355.429)	-215.780 (709.735)	-2152.741 (897.412)**	-1174.186 (1564.914)
Natural gas capacity ratio	15340.955 (15218.669)	-5060.241 (8311.231)	-24538.011 (10652.023)**	-10276.006 (19007.109)
NG price * NG capacity ratio	-4017.246 (2930.823)	568.068 (1571.024)	4749.251 (1994.716)**	3851.759 (3491.791)
Risk-free	-220.776 (159.471)	-101.057 (95.857)	-246.281 (116.913)**	-5.005 (223.683)
Lag of Profits	0.289 (0.117)**	0.089 (0.105)	0.072 (0.155)	0.046 (0.116)
Constant	-6931.295 (7464.687)	2441.702 (4051.244)	12400.532 (5186.631)**	2220.104 (9326.667)
R-square	0.599		AIC	4304.157
Chi2-stat.	93.385 (0.000)		BIC	4433.690
n	64		Root MSE	1009.614

Note: SUR standard errors are in parentheses.

Table V-F9: Panel H: SUR estimates for configuration (VIII)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	-1.100 (0.443)**	0.158 (1.171)	0.779 (0.498)	0.224 (0.284)
1 / t	-33383.132 (7198.854)****	-725.211 (6626.271)	-2386.471 (1814.661)	9093.796 (4305.214)**
MCP / t	32.855 (6.336)****	-0.687 (13.720)	-58.856 (26.819)**	-7.859 (9.545)
HDD PosDev onzn	-1.986 (1.252)	-0.468 (0.826)	-1.026 (1.068)	-0.690 (1.864)
HDD NegDev onzn	-5.060 (5.320)	-2.587 (4.184)	2.711 (4.549)	-18.557 (9.571)*
CDD PosDev onzn	-13.417 (10.664)	9.895 (5.289)*	0.616 (9.183)	-16.256 (11.405)
CDD NegDev onzn	-61.018 (23.970)**	-2.695 (9.364)	27.604 (24.547)	-6.065 (22.635)
HDD PosDev external	1.535 (6.274)	-1.570 (4.557)	-0.228 (4.681)	-11.040 (8.886)
HDD NegDev external	2.154 (7.742)	3.665 (6.030)	-3.755 (6.574)	12.251 (13.712)
CDD PosDev external	49.051 (14.549)****	10.547 (8.658)	-9.533 (12.154)	8.868 (15.228)
CDD NegDev external	39.900 (22.083)*	0.158 (8.229)	-1.837 (20.326)	57.949 (18.969)***
Natural gas price	2660.353 (1199.923)**	-226.253 (845.347)	-1424.551 (947.047)	-2619.863 (1753.034)
Natural gas capacity ratio	18495.204 (13004.250)	-5237.210 (8817.436)	-20002.726 (10561.538)*	-22131.013 (19688.417)
NG price * NG capacity ratio	-5175.377 (2616.300)**	538.596 (1895.858)	3028.099 (2132.398)	7393.735 (3967.781)*
Risk-free	-238.021 (136.841)*	-100.574 (98.556)	-290.468 (116.111)**	-21.833 (216.543)
Lag of Profits	0.192 (0.101)*	0.133 (0.135)	0.010 (0.155)	0.046 (0.116)
Constant	-8701.169 (6341.659)	2664.936 (4159.235)	10944.990 (5069.996)**	6490.687 (9455.882)
R-square	0.710		AIC	4286.019

Chi2-stat.	160.520 (0.000)		BIC	4432.823
n	64		Root MSE	858.836

Note: SUR standard errors are in parentheses.

Table V-F10: SUR: misi to onzn: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	0.1 (0.771)	0.7 (0.393)	4.0 (0.046)	3.1 (0.077)
Hypothesis B	25.4 (0.000)	4.6 (0.032)	3.9 (0.047)	0.0 (0.907)
Hypothesis C	0.4 (0.529)	2.5 (0.113)	1.3 (0.247)	8.7 (0.003)
Hypothesis D	1.3 (0.511)	2.5 (0.283)	4.4 (0.111)	10.4 (0.006)
Hypothesis E		3.7 (0.054)		4.1 (0.042)
Hypothesis F		8.4 (0.004)		10.4 (0.001)
Hypothesis G		9.6 (0.008)		11.0 (0.004)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F10: SUR: misi to onzn: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	0.6 (0.449)	5.3 (0.021)	0.9 (0.353)	1.9 (0.170)
Hypothesis B	15.1 (0.000)	0.3 (0.604)	4.2 (0.042)	6.2 (0.013)
Hypothesis C	0.1 (0.744)	7.7 (0.005)	0.8 (0.364)	22.4 (0.000)
Hypothesis D	0.6 (0.724)	7.9 (0.020)	1.3 (0.515)	22.5 (0.000)
Hypothesis E		8.2 (0.004)		21.5 (0.000)
Hypothesis F		11.8 (0.001)		26.9 (0.000)
Hypothesis G		14.4 (0.001)		27.9 (0.000)
Hypothesis J	14.2 (0.000)	16.2 (0.000)	6.1 (0.013)	3.6 (0.058)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F11: SUR: nysi to onzn: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	2.9 (0.090)	0.2 (0.691)	1.8 (0.177)	0.7 (0.413)
Hypothesis B	0.0 (0.881)	0.7 (0.403)	0.8 (0.386)	0.2 (0.690)
Hypothesis C	2.9 (0.088)	0.3 (0.573)	4.5 (0.033)	0.7 (0.400)
Hypothesis D	3.5 (0.173)	1.3 (0.529)	7.6 (0.023)	1.4 (0.499)
Hypothesis E		32.6 (0.000)		35.9 (0.000)
Hypothesis F		10.0 (0.002)		4.9 (0.027)
Hypothesis G		37.6 (0.000)		47.2 (0.000)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F11: SUR: nysi to onzn: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	2.7 (0.102)	0.1 (0.733)	0.4 (0.547)	0.4 (0.522)
Hypothesis B	0.2 (0.628)	1.6 (0.209)	0.3 (0.598)	0.0 (0.893)
Hypothesis C	5.8 (0.016)	0.0 (0.934)	4.2 (0.041)	0.5 (0.472)
Hypothesis D	5.8 (0.055)	0.1 (0.936)	5.4 (0.067)	1.2 (0.553)
Hypothesis E		0.1 (0.699)		0.0 (0.913)
Hypothesis F		0.9 (0.351)		0.0 (0.960)
Hypothesis G		2.8 (0.249)		0.2 (0.888)
Hypothesis J	5.3 (0.021)	6.9 (0.008)	0.7 (0.398)	1.0 (0.322)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F12: SUR: onzn to misi: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	3.9 (0.048)	5.4 (0.020)	3.5 (0.060)	4.6 (0.033)
Hypothesis B	5.2 (0.023)	5.2 (0.023)	0.1 (0.789)	1.6 (0.211)
Hypothesis C	3.5 (0.060)	0.3 (0.555)	9.8 (0.002)	1.4 (0.245)
Hypothesis D	4.9 (0.087)	5.4 (0.068)	11.5 (0.003)	5.5 (0.065)
Hypothesis E		0.5 (0.471)		1.1 (0.303)
Hypothesis F		1.3 (0.262)		2.5 (0.117)
Hypothesis G		2.0 (0.361)		3.3 (0.190)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F12: SUR: onzn to misi: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	3.7 (0.053)	5.5 (0.019)	5.7 (0.017)	4.7 (0.031)
Hypothesis B	4.2 (0.040)	3.5 (0.063)	0.0 (0.853)	2.5 (0.117)
Hypothesis C	2.7 (0.101)	0.5 (0.485)	8.2 (0.004)	0.2 (0.657)
Hypothesis D	4.3 (0.114)	5.5 (0.064)	12.5 (0.002)	4.7 (0.096)
Hypothesis E		0.9 (0.354)		1.7 (0.188)
Hypothesis F		0.8 (0.367)		4.8 (0.028)
Hypothesis G		2.1 (0.349)		5.9 (0.053)
Hypothesis J	0.4 (0.539)	0.3 (0.584)	0.2 (0.642)	0.0 (0.946)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F13: SUR: onzn to nysi: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	2.5 (0.111)	3.5 (0.061)	1.3 (0.253)	0.9 (0.333)
Hypothesis B	13.1 (0.000)	9.1 (0.003)	1.5 (0.225)	1.2 (0.277)
Hypothesis C	2.0 (0.159)	1.1 (0.298)	15.4 (0.000)	7.1 (0.008)
Hypothesis D	2.7 (0.257)	3.5 (0.170)	15.4 (0.000)	7.2 (0.028)
Hypothesis E		0.1 (0.759)		1.3 (0.263)
Hypothesis F		0.2 (0.655)		0.1 (0.699)
Hypothesis G		0.8 (0.663)		1.3 (0.524)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F13: SUR: onzn to nysi: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	4.7 (0.030)	5.2 (0.022)	0.1 (0.812)	0.5 (0.492)
Hypothesis B	1.9 (0.171)	1.1 (0.301)	0.2 (0.666)	0.6 (0.429)
Hypothesis C	7.4 (0.007)	4.4 (0.037)	16.9 (0.000)	7.5 (0.006)
Hypothesis D	7.5 (0.024)	6.1 (0.047)	17.4 (0.000)	7.5 (0.024)
Hypothesis E		0.2 (0.661)		4.5 (0.035)
Hypothesis F		0.0 (0.883)		0.7 (0.410)
Hypothesis G		0.8 (0.670)		4.6 (0.100)
Hypothesis J	3.8 (0.053)	3.8 (0.050)	0.2 (0.690)	0.0 (0.874)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F14: SUR: All paths jointly: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	8.9 (0.064)	9.7 (0.046)	11.9 (0.018)	9.6 (0.047)
Hypothesis B	44.2 (0.000)	18.2 (0.001)	6.6 (0.162)	2.9 (0.570)
Hypothesis C	9.1 (0.059)	3.9 (0.422)	30.0 (0.000)	17.3 (0.002)
Hypothesis D	12.1 (0.147)	12.2 (0.142)	39.0 (0.000)	24.1 (0.002)
Hypothesis E		55.5 (0.000)		49.7 (0.000)
Hypothesis F		31.0 (0.000)		21.3 (0.000)
Hypothesis G		66.1 (0.000)		66.8 (0.000)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F14: SUR: All paths jointly: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	10.7 (0.030)	16.2 (0.003)	7.0 (0.136)	6.8 (0.148)
Hypothesis B	22.4 (0.000)	6.0 (0.197)	4.9 (0.298)	9.3 (0.054)
Hypothesis C	15.5 (0.004)	12.7 (0.013)	28.9 (0.000)	30.4 (0.000)
Hypothesis D	17.9 (0.022)	19.4 (0.013)	35.8 (0.000)	35.5 (0.000)
Hypothesis E		10.8 (0.029)		27.9 (0.000)
Hypothesis F		16.4 (0.002)		31.9 (0.000)
Hypothesis G		24.6 (0.002)		39.1 (0.000)
Hypothesis J	22.1 (0.000)	25.2 (0.000)	7.2 (0.127)	4.4 (0.337)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-F15: 90% confidence intervals for MCP: Panel A: misi to onzn

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	0.881	1.278	1.664	0.600	1.278	1.946	0.770	1.143	1.516
(II)	0.320	0.805	1.291	-0.069	0.805	1.680	0.133	0.575	1.016
(III)	0.177	0.746	1.315	0.125	0.746	1.367	0.108	0.632	1.155
(IV)	-0.390	0.248	0.887	-0.416	0.248	0.913	-0.621	-0.041	0.539
(V)	0.703	1.110	1.518	0.493	1.110	1.727	0.532	0.922	1.313
(VI)	-0.257	0.273	0.803	-0.524	0.273	1.070	-0.342	0.157	0.657
(VII)	0.089	0.724	1.358	0.019	0.724	1.429	0.133	0.692	1.250
(VIII)	-1.750	-0.907	-0.065	-1.843	-0.907	0.028	-1.829	-1.100	-0.371

Table V-F15: 90% confidence intervals for MCP: Panel B: nysi to onzn

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	-1.131	-0.155	0.821	-0.436	-0.155	0.126	-1.155	-0.096	0.962
(II)	-0.903	0.132	1.167	-0.122	0.132	0.387	-0.577	0.597	1.772
(III)	-2.076	-0.810	0.456	-1.726	-0.810	0.106	-1.993	-0.688	0.617
(IV)	-1.702	-0.391	0.921	-1.524	-0.391	0.743	-1.005	0.322	1.648
(V)	-1.068	-0.215	0.638	-0.669	-0.215	0.239	-1.111	-0.253	0.605
(VI)	-0.516	0.692	1.900	-0.126	0.692	1.510	-0.289	0.938	2.166
(VII)	-1.506	-0.352	0.802	-1.061	-0.352	0.358	-1.429	-0.347	0.735
(VIII)	-2.100	-0.029	2.042	-1.131	-0.029	1.074	-1.769	0.158	2.084

Table V-F15: 90% confidence intervals for MCP: Panel C: onzn to misi

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	0.332	0.491	0.649	0.404	0.491	0.577	0.153	0.548	0.943
(II)	0.262	0.750	1.238	0.534	0.750	0.966	0.218	0.794	1.369
(III)	0.226	0.419	1.611	0.277	0.419	0.561	-0.410	0.076	0.562
(IV)	0.159	0.796	1.433	0.453	0.796	1.139	-0.163	0.518	1.200
(V)	0.247	0.481	0.716	0.330	0.481	0.633	0.110	0.556	1.002
(VI)	0.143	0.684	1.226	0.464	0.684	0.905	0.084	0.727	1.370
(VII)	0.005	0.301	0.598	0.085	0.301	0.518	-0.479	0.061	0.600
(VIII)	0.220	1.000	1.780	0.597	1.000	1.402	-0.039	0.779	1.598

Table V-F15: 90% confidence intervals for MCP: Panel D: onzn to nysi

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	0.311	0.649	0.988	0.418	0.649	0.881	0.392	0.720	1.047
(II)	0.277	0.703	1.129	0.456	0.703	0.950	0.338	0.744	1.149
(III)	-0.146	0.211	0.568	-0.133	0.211	0.556	-0.084	0.236	0.557
(IV)	-0.214	0.285	0.784	-0.108	0.285	0.678	-0.148	0.289	0.727
(V)	-0.100	0.308	0.716	0.100	0.308	0.516	-0.067	0.335	0.737
(VI)	-0.243	0.302	0.847	0.014	0.302	0.589	-0.196	0.331	0.858
(VII)	-0.318	0.091	0.499	-0.215	0.091	0.386	-0.267	0.095	0.457
(VIII)	-0.338	0.212	0.762	-0.155	0.212	0.579	-0.243	0.224	0.692

Appendix V-G: Estimation results for path-by-path Tobit analysis with ST FTR data

Table V-G1: Panel A: Tobit: misi to onzn: Estimates and diagnostic tests

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
MCP	1.924 (0.328)****	1.924 (0.480)****	1.406 (0.389)****	1.406 (0.563)**
1 / t			-2487.539 (2735.566)	-2487.539 (2984.992)
MCP / t			7.551 (4.029)*	7.551 (6.842)
Constant	-997.751 (323.531)***	-997.751 (332.309)***	-918.205 (326.108)***	-918.205 (311.378)***
Sigma	1637.886 (171.831)****	1637.886 (286.277)****	1562.496 (163.702)****	1562.496 (233.009)****
MacKinnon R2	0.035	0.035	0.041	0.041
McK.-Zav. R2	0.361	0.361	0.404	0.404
Cragg-Uhl. R2	0.347	0.347	0.391	0.391
Cox-Snell R2	0.347	0.347	0.391	0.391
AIC	864.240	864.240	863.056	863.056
BIC	871.152	871.152	874.576	874.576
Overall Chi2	31.152 (0.000)		36.667 (0.000)	
Overall F-stat		16.033 (0.000)		7.218 (0.000)
N	74	74	74	74

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G1: Panel B: Tobit: misi to onzn: Estimates and diagnostic tests

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
MCP	1.105 (0.403)***	1.105 (0.427)**	0.686 (0.444)	0.686 (0.467)
HDD PosDev onzn	-3.384 (1.723)*	-3.384 (1.315)**	-2.418 (1.726)	-2.418 (1.295)*
HDD NegDev	-3.241	-3.241	-7.245	-7.245

onzn	(8.286)	(5.436)	(8.206)	(6.510)
CDD PosDev onzn	-4.804 (15.267)	-4.804 (19.191)	-7.773 (14.636)	-7.773 (18.120)
CDD NegDev onzn	-74.142 (29.467)**	-74.142 (20.551)****	-72.106 (28.018)**	-72.106 (20.607)****
HDD PosDev misi	13.061 (7.416)*	13.061 (11.326)	9.462 (7.402)	9.462 (7.750)
HDD NegDev misi	-10.524 (11.483)	-10.524 (6.516)	-5.923 (11.202)	-5.923 (7.827)
CDD PosDev misi	44.875 (19.460)**	44.875 (25.743)*	49.974 (18.745)***	49.974 (25.252)*
CDD NegDev misi	20.596 (32.132)	20.596 (20.294)	29.334 (30.622)	29.334 (21.522)
Natural gas price	5439.132 (1637.640)***	5439.132 (1665.087)***	4480.272 (1620.854)***	4480.272 (1682.395)***
Natural gas capacity ratio	51719.445 (18287.992)***	51719.445 (17282.491)***	45082.373 (17804.048)**	45082.373 (16657.430)***
NG price * NG capacity ratio	-11869.229 (3594.187)***	-11869.229 (3729.403)***	-9458.635 (3595.458)**	-9458.635 (3737.422)**
Risk-free	-55.276 (197.922)	-55.276 (175.414)	14.401 (194.771)	14.401 (173.521)
1 / t			-1934.510 (2161.510)	-1934.510 (2187.645)
MCP / t			6.820 (3.649)	6.820 (5.685)
Constant	-24795.729 (8914.986)***	-24795.729 (8289.011)***	-22682.469 (8650.471)**	-22682.469 (7957.942)***
Sigma	1195.748 (124.510)****	1195.748 (170.007)****	1141.813 (119.102)****	1141.813 (133.283)****
MacKinnon R2	0.076	0.076	0.080	0.080
McK.-Zav. R2	0.667	0.667	0.684	0.684
Cragg-Uhl. R2	0.597	0.597	0.619	0.619
Cox-Snell R2	0.597	0.597	0.619	0.619
AIC	852.388	852.388	852.304	852.304
BIC	886.949	886.949	891.473	891.473
Overall Chi2	67.335 (0.000)		71.419 (0.000)	
Overall F-stat		3.419 (0.001)		3.752 (0.000)
N	74	74	74	74

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G1: Panel C: Tobit: misi to onzn: Estimates and diagnostic tests

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
MCP	1.661 (0.331)****	1.661 (0.493)***	0.802 (0.420)*	0.802 (0.564)
Lag of Profit	0.419 (0.147)***	0.419 (0.166)**	0.405 (0.135)***	0.405 (0.192)**
1 / t			-17560.752 (9288.223)*	-17560.752 (13218.720)
MCP / t			19.909 (8.341)**	19.909 (13.713)
Constant	-822.756 (324.714)**	-822.756 (347.827)**	-330.347 (377.938)	-330.347 (369.932)
Sigma	1556.138 (170.737)****	1556.138 (336.065)****	1418.938 (156.517)****	1418.938 (215.012)****
MacKinnon R2	0.043	0.043	0.052	0.052
McK.-Zav. R2	0.427	0.427	0.494	0.494
Cragg-Uhl. R2	0.414	0.414	0.477	0.477
Cox-Snell R2	0.414	0.414	0.477	0.477
AIC	787.690	787.690	784.173	784.173
BIC	796.448	796.448	797.311	797.311
Overall Chi2	35.245 (0.000)		42.762 (0.000)	
Overall F-stat		13.819 (0.000)		7.029 (0.000)
N	66	66	66	66

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G1: Panel D: Tobit: misi to onzn: Estimates and diagnostic tests

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
MCP	1.070 (0.442)**	1.070 (0.486)**	-0.705 (0.571)	-0.705 (0.515)
HDD PosDev onzn	-3.150 (1.737)*	-3.150 (1.368)**	-2.852 (1.538)*	-2.852 (1.219)**
HDD NegDev onzn	-6.581 (8.470)	-6.581 (5.805)	-8.100 (7.230)	-8.100 (5.815)
CDD PosDev onzn	-5.190 (15.661)	-5.190 (18.260)	-3.496 (13.435)	-3.496 (17.785)
CDD NegDev onzn	-44.762 (34.623)	-44.762 (22.901)*	-79.032 (30.627)**	-79.032 (27.643)***
HDD PosDev misi	16.020 (8.140)*	16.020 (13.466)*	1.819 (7.838)	1.819 (7.554)
HDD NegDev misi	-7.801 (12.172)	-7.801 (7.995)	-2.198 (10.270)	-2.198 (7.593)
CDD PosDev misi	38.498 (20.823)*	38.498 (27.347)	45.075 (17.751)**	45.075 (26.776)*
CDD NegDev misi	2.967 (33.978)	2.967 (20.048)	32.712 (29.413)	32.712 (23.781)
Natural gas price	4302.793 (1869.502)**	4302.793 (1773.397)**	5671.853 (1763.537)***	5671.853 (1695.693)***
Natural gas capacity ratio	40375.280 (20436.349)*	40375.280 (17763.828)**	50412.902 (18315.126)***	50412.902 (16142.917)***
NG price * NG capacity ratio	-9330.426 (4035.876)**	-9330.426 (3909.478)**	-11849.649 (3836.874)***	-11849.649 (3650.632)***
Risk-free	-107.714 (215.983)	-107.714 (187.949)	-64.722 (188.819)	-64.722 (167.422)
Lag of Profit	0.211 (0.145)	0.211 (0.140)	0.093 (0.127)	0.093 (0.149)
1 / t			-30937.384 (9074.714)***	-30937.384 (8130.219)***
MCP / t			30.296 (7.823)****	30.296 (7.387)****
Constant	-19369.168 (10065.614)*	-19369.168 (8508.889)**	-24411.848 (8929.573)***	-24411.848 (7847.695)***
Sigma	1184.824 (128.547)****	1184.824 (181.290)****	1003.104 (109.602)****	1003.104 (121.932)****

MacKinnon R2	0.079	0.079	0.095	0.095
McK.-Zav. R2	0.679	0.679	0.753	0.753
Cragg-Uhl. R2	0.623	0.623	0.692	0.692
Cox-Snell R2	0.623	0.623	0.692	0.692
AIC	782.588	782.588	773.299	773.299
BIC	817.622	817.622	812.713	812.713
Overall Chi2	64.347 (0.000)		77.635 (0.000)	
Overall F-stat		3.725 (0.000)		6.655 (0.000)
N	66	66	66	66

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G2: Panel A: Tobit: misi to onzn: Hypothesis test results

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
Hypothesis A	9.5 (0.003)	9.0 (0.004)	7.9 (0.006)	8.7 (0.004)
Hypothesis B	34.3 (0.000)	16.0 (0.000)	13.0 (0.001)	6.2 (0.015)
Hypothesis C	7.9 (0.006)	3.7 (0.058)	1.1 (0.301)	0.5 (0.473)
Hypothesis D	5.1 (0.009)	5.2 (0.008)	4.6 (0.013)	6.4 (0.003)
Hypothesis E			0.8 (0.366)	0.7 (0.407)
Hypothesis F			3.5 (0.065)	1.2 (0.273)
Hypothesis G			2.7 (0.075)	1.2 (0.294)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G2: Panel B: Tobit: misi to onzn: Hypothesis test results

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
Hypothesis A	7.7 (0.007)	8.9 (0.004)	6.9 (0.011)	8.1 (0.006)
Hypothesis B	7.5 (0.008)	6.7 (0.012)	2.4 (0.127)	2.2 (0.148)
Hypothesis C	0.1 (0.796)	0.1 (0.807)	0.5 (0.482)	0.5 (0.504)
Hypothesis D	4.5 (0.015)	4.6 (0.014)	3.5 (0.038)	4.1 (0.022)
Hypothesis E			0.8 (0.374)	0.8 (0.380)
Hypothesis F			3.5 (0.067)	1.4 (0.235)
Hypothesis G			2.1 (0.126)	0.8 (0.437)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G2: Panel C: Tobit: misi to onzn: Hypothesis test results

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
Hypothesis A	6.4 (0.014)	5.6 (0.021)	0.8 (0.385)	0.8 (0.375)
Hypothesis B	25.2 (0.000)	11.3 (0.001)	3.7 (0.061)	2.0 (0.160)
Hypothesis C	4.0 (0.050)	1.8 (0.185)	0.2 (0.639)	0.1 (0.727)
Hypothesis D	3.2 (0.046)	4.0 (0.024)	1.9 (0.155)	2.4 (0.102)
Hypothesis E			3.6 (0.063)	1.8 (0.189)
Hypothesis F			5.7 (0.020)	2.1 (0.152)
Hypothesis G			4.1 (0.322)	1.2 (0.322)
Hypothesis J	8.1 (0.006)	6.4 (0.014)	4.5 (0.038)	4.5 (0.038)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G2: Panel D: Tobit: misi to onzn: Hypothesis test results

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
Hypothesis A	3.7 (0.060)	5.2 (0.027)	7.5 (0.009)	9.7 (0.003)
Hypothesis B	5.9 (0.019)	4.8 (0.032)	1.5 (0.223)	1.9 (0.177)
Hypothesis C	0.0 (0.875)	0.0 (0.886)	8.9 (0.004)	11.0 (0.002)
Hypothesis D	2.2 (0.120)	2.8 (0.069)	6.0 (0.005)	6.4 (0.003)
Hypothesis E			11.6 (0.001)	14.5 (0.000)
Hypothesis F			15.0 (0.000)	16.8 (0.000)
Hypothesis G			8.0 (0.001)	8.7 (0.001)
Hypothesis J	2.1 (0.150)	2.3 (0.136)	0.5 (0.465)	0.4 (0.533)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G3: Panel A: Tobit: nysi to onzn: Estimates and diagnostic tests

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
MCP	1.033 (1.785)	1.033 (1.150)	2.350 (1.912)	2.350 (1.352)
1 / t			9777.142 (3182.708)***	9777.142 (2109.251)****
MCP / t			-31.365 (17.671)*	-31.365 (12.651)**
Constant	-1629.290 (538.495)***	-1629.290 (599.333)***	-1631.940 (463.474)****	-1631.940 (640.564)**
Sigma	1960.481 (352.178)****	1960.481 (625.255)***	1529.427 (272.086)****	1529.427 (613.897)**
MacKinnon R2	0.001	0.001	0.031	0.031
McK.-Zav. R2	0.007	0.007	0.188	0.188
Cragg-Uhl. R2	0.005	0.005	0.148	0.148
Cox-Snell R2	0.005	0.005	0.148	0.148
AIC	392.530	392.530	384.888	384.888
BIC	399.483	399.483	396.475	396.475
Overall Chi2	0.339 (0.560)		11.981 (0.007)	
Overall F-stat		0.806 (0.0372)		33.909 (0.000)
N	75	75	75	75

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G3: Panel B: Tobit: nysi to onzn: Estimates and diagnostic tests

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
MCP	-2.457 (1.822)	-2.457 (1.591)	-1.179 (1.877)	-1.179 (1.711)
HDD PosDev onzn	-27.000 (24.969)	-27.000 (14.694)	-14.375 (20.180)	-14.375 (11.306)
HDD NegDev onzn	-10.313 (14.012)	-10.313 (12.239)	-5.609 (12.553)	-5.609 (10.811)

CDD PosDev onzn	7.250 (12.208)	7.250 (12.785)	11.624 (10.475)	11.624 (10.660)
CDD NegDev onzn	-186.660 (266.918)	-186.660 (146.215)	-124.498 (166.137)	-124.498 (92.029)
HDD PosDev nysi	-336.643 (287.202)	-336.643 (189.688)*	-228.909 (198.667)	-228.909 (121.755)*
HDD NegDev nysi	13.544 (21.110)	13.544 (17.762)	7.953 (19.023)	7.953 (16.044)
CDD PosDev nysi	28.453 (15.254)*	28.453 (18.477)	25.932 (12.769)**	25.932 (20.328)
CDD NegDev nysi	19.037 (172.496)	19.037 (112.261)	40.623 (83.761)	40.623 (43.074)
Natural gas price	-9414.112 (3682.522)**	-9414.112 (4345.498)**	-6505.301 (3247.713)**	-6505.301 (3727.158)*
Natural gas capacity ratio	-138664.624 (45748.576)***	-138664.624 (58620.004)**	-92380.383 (40760.243)**	-92380.383 (52844.786)*
NG price * NG capacity ratio	21175.670 (8255.054)**	21175.670 (9709.367)**	14875.205 (7297.152)**	14875.205 (8400.698)*
Risk-free	-1375.659 (397.957)****	-1375.659 (538.718)**	-862.802 (366.162)**	-862.802 (509.802)*
1 / t			5137.244 (2449.684)**	5137.244 (1576.878)***
MCP / t			-9.715 (15.649)	-9.715 (9.133)
Constant	66311.247 (21623.485)***	66311.247 (28100.921)**	42737.759 (19367.439)**	42737.759 (25132.160)*
Sigma	1201.116 (200.955)****	1201.116 (211.218)****	1025.863 (169.940)****	1025.863 (267.066)****
MacKinnon R2	0.111	0.111	0.128	0.128
McK.-Zav. R2	0.978	0.978	0.966	0.966
Cragg-Uhl. R2	0.440	0.440	0.487	0.487
Cox-Snell R2	0.437	0.437	0.487	0.487
AIC	373.768	373.768	371.269	371.269
BIC	408.530	408.530	410.667	410.667
Overall Chi2	43.102 (0.000)		49.600 (0.000)	
Overall F-stat		1.082 (0.433)		67.895 (0.000)
N	75	75	75	75

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses.

Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G3: Panel C: Tobit: nysi to onzn: Estimates and diagnostic tests

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
MCP	-0.053 (1.568)	-0.053 (1.313)	2.552 (2.176)	2.552 (2.018)
Lag of Profit	0.539 (0.229)**	0.539 (0.354)	0.664 (0.243)***	0.664 (0.421)
1 / t			7472.889 (13570.162)	7472.889 (11791.871)
MCP / t			-30.851 (31.920)	-30.851 (30.479)
Constant	-1197.953 (421.943)***	-1197.953 (521.260)**	-1465.301 (564.147)**	-1465.301 (728.989)**
Sigma	1475.351 (274.351)****	1475.351 (521.260)**	1403.705 (564.147)**	1403.705 (728.278)**
MacKinnon R2	0.016	0.016	0.024	0.024
McK.-Zav. R2	0.092	0.092	0.154	0.154
Cragg-Uhl. R2	0.076	0.076	0.113	0.113
Cox-Snell R2	0.076	0.076	0.112	0.112
AIC	342.828	342.828	344.053	344.053
BIC	351.706	351.706	357.370	357.370
Overall Chi2	5.304 (0.071)		8.079 (0.089)	
Overall F-stat		1.157 (0.321)		0.665 (0.618)
N	68	68	68	68

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G3: Panel D: Tobit: nysi to onzn: Estimates and diagnostic tests

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
MCP	-0.615 (2.036)	-0.615 (1.750)	-2.467 (4.218)	-2.467 (3.237)
HDD PosDev onzn	-15.088 (22.357)	-15.088 (11.807)	-17.398 (25.111)	-17.398 (11.790)
HDD NegDev onzn	-5.692 (12.384)	-5.692 (10.163)	-5.047 (14.094)	-5.047 (11.310)
CDD PosDev onzn	13.810 (11.487)	13.810 (10.293)	17.760 (12.677)	17.760 (10.162)
CDD NegDev onzn	-113.589 (174.057)	-113.589 (98.748)	-60.054 (195.779)	-60.054 (101.373)
HDD PosDev nysi	-223.132 (225.165)	-223.132 (142.422)	-170.042 (214.580)	-170.042 (116.717)
HDD NegDev nysi	7.222 (18.928)	7.222 (14.964)	5.584 (21.085)	5.584 (17.333)
CDD PosDev nysi	25.114 (18.093)	25.114 (24.478)	23.821 (21.339)	23.821 (28.272)
CDD NegDev nysi	24.854 (127.056)	24.854 (71.929)	-29.475 (180.321)	-29.475 (84.091)
Natural gas price	-6391.388 (3572.340)*	-6391.388 (4031.916)	-4208.108 (4347.164)	-4208.108 (4584.164)
Natural gas capacity ratio	-90737.408 (44670.505)**	-90737.408 (56175.831)	-72953.417 (48646.618)	-72953.417 (59457.181)
NG price * NG capacity ratio	14677.318 (8021.411)*	14677.318 (9115.169)	9756.422 (9830.042)	9756.422 (10374.824)
Risk-free	-829.158 (393.469)**	-829.158 (393.469)**	-856.353 (410.095)**	-856.353 (520.253)
Lag of Profit	0.012 (0.277)	0.012 (0.277)	0.024 (0.363)	0.024 (0.307)
1 / t			-25776,440 (36497.954)	-25776,440 (23590.298)
MCP / t			50.414 (79.414)	50.414 (51.971)
Constant	41786.821 (21119.603)*	41786.821 (26457.994)	34699.214 (22391.899)	34699.214 (27558.806)
Sigma	1065.696 (186.151)****	1065.696 (283.954)****	1074.462 (189.103)****	1074.462 (293.932)****
MacKinnon R2	0.107	0.107	0.109	0.109

McK.-Zav. R2	0.960	0.960	0.939	0.939
Cragg-Uhl. R2	0.417	0.417	0.422	0.422
Cox-Snell R2	0.414	0.414	0.419	0.419
AIC	335.791	335.791	339.155	339.155
BIC	371.342	371.342	379.106	379.106
Overall Chi2	36.342 (0.001)		36.978 (0.002)	
Overall F-stat		0.964 (0.501)		1.439 (0.161)
N	68	68	68	68

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G4: Panel A: Tobit: nysi to onzn: Hypothesis test results

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
Hypothesis A	9.2 (0.003)	7.4 (0.008)	12.4 (0.001)	6.5 (0.013)
Hypothesis B	0.3 (0.565)	0.8 (0.372)	1.5 (0.223)	3.0 (0.086)
Hypothesis C	0.0 (0.985)	0.0 (0.977)	0.5 (0.482)	1.0 (0.321)
Hypothesis D	6.9 (0.002)	4.9 (0.010)	7.9 (0.001)	4.2 (0.018)
Hypothesis E			9.4 (0.003)	21.5 (0.000)
Hypothesis F			3.2 (0.080)	6.1 (0.016)
Hypothesis G			6.5 (0.003)	46.0 (0.000)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G4: Panel B: Tobit: nysi to onzn: Hypothesis test results

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
Hypothesis A	9.4 (0.003)	5.6 (0.021)	4.9 (0.031)	2.9 (0.094)
Hypothesis B	1.8 (0.182)	2.4 (0.128)	0.4 (0.532)	0.5 (0.493)
Hypothesis C	3.6 (0.062)	4.7 (0.034)	1.3 (0.250)	1.6 (0.208)
Hypothesis D	5.8 (0.005)	3.2 (0.046)	2.6 (0.084)	1.5 (0.242)
Hypothesis E			4.4 (0.040)	10.6 (0.002)
Hypothesis F			0.4 (0.537)	1.1 (0.292)
Hypothesis G			3.8 (0.028)	8.4 (0.001)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G4: Panel C: Tobit: nysi to onzn: Hypothesis test results

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
Hypothesis A	8.1 (0.006)	5.3 (0.025)	6.7 (0.012)	4.0 (0.049)
Hypothesis B	0.0 (0.973)	0.0 (0.968)	1.4 (0.245)	1.6 (0.211)
Hypothesis C	0.5 (0.504)	0.6 (0.425)	0.5 (0.478)	0.6 (0.445)
Hypothesis D	7.4 (0.001)	3.4 (0.038)	4.0 (0.022)	2.7 (0.073)
Hypothesis E			0.3 (0.584)	0.4 (0.529)
Hypothesis F			0.9 (0.337)	1.0 (0.315)
Hypothesis G			1.2 (0.317)	0.9 (0.398)
Hypothesis J	5.5 (0.022)	2.3 (0.133)	7.5 (0.008)	2.5 (0.120)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G4: Panel D: Tobit: nysi to onzn: Hypothesis test results

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
Hypothesis A	3.9 (0.053)	2.5 (0.120)	2.4 (0.127)	1.6 (0.214)
Hypothesis B	0.1 (0.764)	0.1 (0.727)	0.3 (0.561)	0.6 (0.450)
Hypothesis C	0.6 (0.431)	0.9 (0.360)	0.7 (0.415)	1.1 (0.289)
Hypothesis D	2.2 (0.119)	1.3 (0.289)	1.6 (0.215)	1.2 (0.306)
Hypothesis E			0.5 (0.483)	1.2 (0.280)
Hypothesis F			0.4 (0.528)	0.9 (0.337)
Hypothesis G			0.3 (0.754)	0.7 (0.489)
Hypothesis J	0.0 (0.967)	0.0 (0.958)	0.0 (0.947)	0.0 (0.937)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G5: Panel A: Tobit: onzn to misi: Estimates and diagnostic tests

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
MCP	0.619 (0.131)****	0.619 (0.131)****	0.658 (0.473)	0.658 (0.473)
1 / t			-9956.870 (4450.913)**	-9956.870 (4450.913)**
MCP / t			-7.463 (26.261)	-7.463 (26.261)
Constant	-178.887 (155.027)	-178.887 (155.027)	271.704 (209.272)	271.704 (209.272)
Sigma	1066.254 (116.725)****	1066.254 (116.725)****	1018.654 (110.191)****	1018.654 (110.191)****
MacKinnon R2	0.024	0.024	0.038	0.038
McK.-Zav. R2	0.240	0.240	0.684	0.684
Cragg-Uhl. R2	0.233	0.233	0.341	0.341
Cox-Snell R2	0.233	0.233	0.341	0.341
AIC	798.198	798.198	790.942	790.942
BIC	805.110	805.110	802.462	802.462
Overall Chi2	19.616 (0.000)	19.616 (0.000)	30.871 (0.000)	30.871 (0.000)
Overall F-stat				
N	74	74	74	74

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G5: Panel B: Tobit: onzn to misi: Estimates and diagnostic tests

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
MCP	0.527 (0.150)****	0.527 (0.111)****	0.838 (0.516)	0.838 (0.396)**
HDD PosDev onzn	-0.993 (1.865)	-0.993 (1.608)	-2.363 (1.940)	-2.363 (1.805)
HDD NegDev onzn	1.493 (6.371)	1.493 (10.730)	2.346 (6.473)	2.346 (10.855)

CDD PosDev onzn	3.843 (12.693)	3.843 (9.252)	6.407 (12.340)	6.407 (8.365)
CDD NegDev onzn	8.028 (22.980)	8.028 (18.154)	13.058 (24.841)	13.058 (22.274)
HDD PosDev misi	-2.104 (6.074)	-2.104 (5.970)	-3.047 (6.203)	-3.047 (6.151)
HDD NegDev misi	-3.912 (9.404)	-3.912 (10.188)	-4.518 (9.305)	-4.518 (10.529)
CDD PosDev misi	-17.361 (17.966)	-17.361 (11.053)	-22.402 (17.577)	-22.402 (11.545)*
CDD NegDev misi	-2.885 (23.752)	-2.885 (26.453)	-12.917 (24.318)	-12.917 (28.092)
Natural gas price	-2120.522 (1098.948)*	-2120.522 (1179.497)*	-777.950 (1209.993)	-777.950 (1074.851)
Natural gas capacity ratio	-20628.307 (12834.022)	-20628.307 (13369.574)	-15242.309 (12743.517)	-15242.309 (13121.033)
NG price * NG capacity ratio	4528.847 (2440.647)*	4528.847 (2510.755)*	1319.144 (2720.941)	1319.144 (2393.349)
Risk-free	-129.648 (147.797)	-129.648 (168.548)	-290.414 (160.876)*	-290.414 (215.164)
1 / t			-12831.137 (6882.401)*	-12831.137 (9246.926)
MCP / t			-21.702 (30.679)	-21.702 (23.399)
Constant	10360.848 (6255.533)	10360.848 (7136.758)	9599.644 (6133.408)	9599.644 (7192.992)
Sigma	975.417 (105.754)****	975.417 (234.367)****	937.587 (101.110)****	937.587 (200.142)****
MacKinnon R2	0.045	0.045	0.054	0.054
McK.-Zav. R2	0.413	0.413	0.770	0.770
Cragg-Uhl. R2	0.392	0.392	0.448	0.448
Cox-Snell R2	0.392	0.392	0.448	0.448
AIC	804.951	804.951	801.833	801.833
BIC	839.512	839.512	841.003	841.003
Overall Chi2	36.863 (0.000)		43.980 (0.000)	
Overall F-stat		4.667 (0.000)		3.649 (0.000)
N	74	74	74	74

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses.

Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G5: Panel C: Tobit: onzn to misi: Estimates and diagnostic tests

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
MCP	0.688 (0.197)****	0.688 (0.139)****	0.696 (0.518)	0.696 (0.458)
Lag of Profit	0.200 (0.186)	0.200 (0.121)	0.156 (0.179)	0.156 (0.113)
1 / t			-9661.521 (4820.604)**	-9661.521 (6740.770)
MCP / t			-8.077 (28.229)	-8.077 (25.217)
Constant	-223.051 (180.129)	-223.051 (135.780)	231.599 (240.454)	231.599 (248.315)
Sigma	1136.761 (134.078)****	1136.761 (302.193)****	1087.460 (126.925)****	1087.460 (248.315)****
MacKinnon R2	0.016	0.016	0.028	0.028
McK.-Zav. R2	0.164	0.164	0.429	0.429
Cragg-Uhl. R2	0.161	0.161	0.260	0.260
Cox-Snell R2	0.161	0.161	0.260	0.260
AIC	701.252	701.252	696.984	696.984
BIC	710.011	710.011	710.122	710.122
Overall Chi2	11.572 (0.003)		19.840 (0.001)	
Overall F-stat		12.755 (0.000)		10.933 (0.000)
N	66	66	66	66

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G5: Panel D: Tobit: onzn to misi: Estimates and diagnostic tests

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
MCP	0.374 (0.217)**	0.374 (0.102)****	1.361 (0.670)**	1.361 (0.415)***
HDD PosDev onzn	-1.563 (2.003)	-1.563 (1.729)	-3.396 (2.100)	-3.396 (1.986)*
HDD NegDev onzn	-2.022 (7.165)	-2.022 (13.264)	-1.543 (7.254)	-1.543 (13.705)
CDD PosDev onzn	0.526 (13.810)	0.526 (12.136)	2.174 (13.123)	2.174 (11.189)
CDD NegDev onzn	26.353 (26.466)	26.353 (19.324)	67.655 (36.818)*	67.655 (28.578)**
HDD PosDev misi	-0.194 (7.369)	-0.194 (6.030)	-1.843 (7.548)	-1.843 (6.640)
HDD NegDev misi	-0.501 (11.250)	-0.501 (13.439)	-1.472 (11.134)	-1.472 (14.273)
CDD PosDev misi	-22.425 (21.375)	-22.425 (13.275)*	-26.165 (20.152)	-26.165 (13.409)
CDD NegDev misi	-20.338 (26.440)	-20.338 (28.626)	-52.421 (31.973)	-52.421 (35.511)
Natural gas price	-2956.030 (1260.323)**	-2956.030 (1471.658)**	-965.748 (1353.488)	-965.748 (1339.638)
Natural gas capacity ratio	-30579.881 (14641.293)**	-30579.881 (16868.124)*	-19593.415 (14171.813)	-19593.415 (15863.541)
NG price * NG capacity ratio	6283.645 (2758.014)**	6283.645 (3114.046)**	1624.980 (3020.889)	1624.980 (2963.117)
Risk-free	-259.226 (168.477)	-259.226 (215.018)	-430.810 (177.516)**	-430.810 (251.403)*
Lag of Profit	0.149 (0.179)	0.149 (0.118)	0.087 (0.175)	0.087 (0.122)
1 / t			-14947.723 (7417.624)**	-14947.723 (9221.668)
MCP / t			-74.694 (45.152)	-74.694 (29.510)**
Constant	15726.290 (7257.686)**	15726.290 (9057.669)**	12653.705 (6894.774)*	12653.705 (8639.209)*
Sigma	1006.234 (116.780)****	1006.234 (249.776)****	941.993 (108.400)****	941.993 (209.361)****
MacKinnon R2	0.044	0.044	0.056	0.056

McK.-Zav. R2	0.404	0.404	0.628	0.628
Cragg-Uhl. R2	0.373	0.373	0.448	0.448
Cox-Snell R2	0.373	0.373	0.448	0.448
AIC	706.025	706.025	701.601	701.601
BIC	741.059	741.059	741.015	741.015
Overall Chi2	30.799 (0.006)		39.223 (0.001)	
Overall F-stat		8.977 (0.000)		12.099 (0.000)
N	66	66	66	66

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G6: Panel A: Tobit: onzn to misi: Hypothesis test results

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
Hypothesis A	1.3 (0.252)	1.3 (0.252)	1.7 (0.198)	1.7 (0.198)
Hypothesis B	22.2 (0.000)	22.2 (0.000)	1.9 (0.169)	1.9 (0.169)
Hypothesis C	8.4 (0.005)	8.4 (0.005)	0.5 (0.472)	0.5 (0.472)
Hypothesis D	7.5 (0.001)	7.5 (0.001)	0.9 (0.028)	0.9 (0.028)
Hypothesis E			5.0 (0.028)	5.0 (0.028)
Hypothesis F			0.1 (0.777)	0.1 (0.777)
Hypothesis G			3.4 (0.039)	3.4 (0.039)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G6: Panel B: Tobit: onzn to misi: Hypothesis test results

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
Hypothesis A	2.7 (0.103)	2.1 (0.152)	2.4 (0.123)	1.8 (0.187)
Hypothesis B	12.4 (0.001)	22.6 (0.000)	2.6 (0.109)	4.5 (0.038)
Hypothesis C	10.0 (0.002)	18.1 (0.000)	0.1 (0.755)	0.2 (0.685)
Hypothesis D	5.7 (0.005)	9.1 (0.000)	1.2 (0.296)	0.9 (0.393)
Hypothesis E			3.5 (0.067)	1.9 (0.170)
Hypothesis F			0.5 (0.482)	0.9 (0.357)
Hypothesis G			1.9 (0.155)	1.3 (0.278)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G6: Panel C: Tobit: onzn to misi: Hypothesis test results

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
Hypothesis A	1.5 (0.220)	2.7 (0.105)	0.9 (0.339)	0.9 (0.355)
Hypothesis B	12.2 (0.001)	24.6 (0.000)	1.8 (0.184)	2.3 (0.134)
Hypothesis C	2.5 (0.119)	5.1 (0.028)	0.3 (0.559)	0.4 (0.509)
Hypothesis D	3.6 (0.033)	8.4 (0.001)	0.5 (0.605)	0.5 (0.632)
Hypothesis E			4.0 (0.049)	2.1 (0.157)
Hypothesis F			0.1 (0.776)	0.1 (0.750)
Hypothesis G			2.7 (0.072)	1.8 (0.169)
Hypothesis J	1.2 (0.287)	2.7 (0.104)	0.8 (0.387)	1.7 (0.197)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G6: Panel D: Tobit: onzn to misi: Hypothesis test results

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
Hypothesis A	4.7 (0.035)	3.0 (0.088)	3.4 (0.072)	2.1 (0.149)
Hypothesis B	3.0 (0.090)	13.6 (0.001)	4.1 (0.048)	10.8 (0.002)
Hypothesis C	8.3 (0.006)	37.9 (0.000)	0.3 (0.593)	0.8 (0.389)
Hypothesis D	5.8 (0.005)	22.0 (0.000)	2.0 (0.141)	1.6 (0.217)
Hypothesis E			4.1 (0.049)	2.6 (0.111)
Hypothesis F			2.7 (0.104)	6.4 (0.015)
Hypothesis G			3.1 (0.056)	3.3 (0.045)
Hypothesis J	0.7 (0.407)	1.6 (0.210)	0.2 (0.620)	0.5 (0.477)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G7: Panel A: Tobit: onzn to nysi: Estimates and diagnostic tests

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
MCP	0.710 (0.215)***	0.710 (0.215)***	0.616 (0.298)**	0.616 (0.298)**
1 / t			-4462.749 (4397.296)	-4462.749 (4397.296)
MCP / t			0.333 (9.911)	0.333 (9.911)
Constant	307.897 (289.595)	307.897 (289.595)	637.467 (341.842)*	637.467 (341.842)*
Sigma	1730.155 (152.075)****	1730.155 (152.075)****	1708.007 (149.722)****	1708.007 (149.722)****
MacKinnon R2	0.009	0.009	0.012	0.012
McK.-Zav. R2	0.133	0.133	0.232	0.232
Cragg-Uhl. R2	0.130	0.130	0.174	0.174
Cox-Snell R2	0.130	0.130	0.174	0.174
AIC	1189.260	1189.260	1189.506	1189.506
BIC	1196.131	1196.131	1200.958	1200.958
Overall Chi2	10.194 (0.001)	10.194 (0.001)	13.947 (0.003)	13.947 (0.003)
Overall F-stat				
N	73	73	73	73

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G7: Panel B: Tobit: onzn to nysi: Estimates and diagnostic tests

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
MCP	0.232 (0.202)	0.232 (0.186)	0.316 (0.281)	0.316 (0.221)
HDD PosDev onzn	-1.211 (1.969)	-1.211 (0.878)	-1.330 (2.009)	-1.330 (0.848)
HDD NegDev onzn	-18.184 (9.470)*	-18.184 (7.627)**	-17.081 (9.849)*	-17.081 (7.864)**

CDD PosDev onzn	16.227 (11.872)	16.227 (7.870)**	-15.858 (11.898)	-15.858 (7.925)*
CDD NegDev onzn	-4.115 (18.922)	-4.115 (15.852)	-2.358 (19.535)	-2.358 (16.696)
HDD PosDev nysi	-7.933 (8.485)	-7.933 (8.118)	-6.506 (9.076)	-6.506 (8.995)
HDD NegDev nysi	7.120 (13.961)	7.120 (10.974)	5.982 (14.272)	5.982 (11.045)
CDD PosDev nysi	7.530 (14.675)	7.530 (8.135)	7.690 (14.671)	7.690 (8.048)
CDD NegDev nysi	46.185 (17.523)**	46.185 (19.538)**	45.469 (17.602)**	45.469 (20.081)**
Natural gas price	-2668.748 (1521.590)*	-2668.748 (1552.333)*	-2384.009 (1659.271)	-2384.009 (1429.295)
Natural gas capacity ratio	-27372.633 (18484.108)	-27372.633 (18600.837)	-25034.115 (19216.661)	-25034.115 (17636.108)
NG price * NG capacity ratio	7292.635 (3405.313)**	7292.635 (3091.615)**	6662.375 (3717.787)*	6662.375 (2930.009)**
Risk-free	-146.894 (215.872)	-146.894 (177.300)	-146.271 (218.181)	-146.271 (176.837)
1 / t			323.307 (2494.874)	323.307 (1646.714)
MCP / t			-4.085 (9.395)	-4.085 (7.859)
Constant	10167.751 (9021.207)	10167.751 (10207.954)	9078.358 (9360.919)	9078.358 (9746.581)
Sigma	1389.949 (121.059)****	1389.949 (295.603)****	1389.041 (121.425)****	1389.041 (295.263)****
MacKinnon R2	0.036	0.036	0.036	0.036
McK.-Zav. R2	0.457	0.457	0.458	0.458
Cragg-Uhl. R2	0.442	0.442	0.443	0.443
Cox-Snell R2	0.442	0.442	0.443	0.443
AIC	1180.927	1180.927	1184.731	1184.731
BIC	1215.284	1215.284	1223.669	1223.669
Overall Chi2	42.526 (0.000)		42.723 (0.000)	
Overall F-stat		6.304 (0.000)		5.372 (0.000)
N	73	73	73	73

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses.

Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G7: Panel C: Tobit: onzn to nysi: Estimates and diagnostic tests

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
MCP	0.343 (0.255)	0.343 (0.143)**	0.266 (0.342)	0.266 (0.241)
Lag of Profit	0.281 (0.134)**	0.281 (0.251)	0.279 (0.134)**	0.279 (0.243)
1 / t			-4286.193 (5092.377)	-4286.193 (3725.144)
MCP / t			0.675 (10.601)	0.675 (8.279)
Constant	505.425 (307.887)	505.425 (236.870)**	770.972 (367.144)**	770.972 (313.578)**
Sigma	1684.291 (155.031)****	1684.291 (475.240)****	1668.284 (153.317)****	1668.284 (475.970)****
MacKinnon R2	0.009	0.009	0.011	0.011
McK.-Zav. R2	0.138	0.138	0.167	0.167
Cragg-Uhl. R2	0.136	0.136	0.159	0.159
Cox-Snell R2	0.136	0.136	0.159	0.159
AIC	1079.622	1079.622	1081.862	1081.862
BIC	1088.381	1088.381	1095.000	1095.000
Overall Chi2	9.647 (0.008)		11.407 (0.022)	
Overall F-stat		6.447 (0.003)		10.023 (0.000)
N	66	66		

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G7 Panel D: Tobit: onzn to nysi: Estimates and diagnostic tests

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
MCP	0.112 (0.225)	0.112 (0.169)	0.257 (0.303)	0.257 (0.233)
HDD PosDev onzn	-0.826 (1.949)	-0.826 (0.876)	-0.496 (1.954)	-0.496 (0.820)
HDD NegDev onzn	-13.704 (9.563)	-13.704 (6.838)*	-18.288 (10.035)*	-18.288 (7.932)**
CDD PosDev onzn	-16.147 (11.946)	-16.147 (7.946)**	-16.807 (11.741)	-16.807 (8.110)**
CDD NegDev onzn	-16.715 (22.330)	-16.715 (18.157)	-8.838 (23.946)	-8.838 (21.498)
HDD PosDev nysi	-8.707 (8.918)	-8.707 (8.504)	-10.289 (9.393)	-10.289 (8.313)
HDD NegDev nysi	2.978 (14.146)	2.978 (10.481)	9.439 (14.560)	9.439 (10.796)
CDD PosDev nysi	10.964 (14.415)	10.964 (7.862)	11.013 (14.122)	11.013 (8.302)
CDD NegDev nysi	59.140 (19.741)***	59.140 (19.031)***	59.682 (19.980)***	59.682 (19.995)***
Natural gas price	-1729.567 (1644.377)	-1729.567 (1468.752)	-2544.332 (1843.884)	-2544.332 (1401.615)*
Natural gas capacity ratio	-16284.783 (19909.037)	-16284.783 (17264.782)	-22245.465 (20694.253)	-22245.465 (16112.531)
NG price * NG capacity ratio	5155.459 (3681.774)	5155.459 (2901.689)*	7172.156 (4172.630)*	7172.156 (3030.343)**
Risk-free	-6.738 (230.672)	-6.738 (160.330)	18.261 (225.123)	18.261 (158.681)
Lag of Profit	0.057 (0.120)	0.057 (0.215)	0.036 (0.119)	0.036 (0.208)
1 / t			7063.995 (4977.026)	7063.995 (4485.631)
MCP / t			-6.573 (10.377)	-6.573 (7.973)
Constant	4711.999 (9737.512)	4711.999 (9614.209)	6569.418 (9930.780)	6569.418 (8861.848)
Sigma	1352.442 (123.607)****	1352.442 (338.754)****	1324.217 (121.483)****	1324.217 (330.544)****
MacKinnon R2	0.035	0.035	0.037	0.037

McK.-Zav. R2	0.454	0.454	0.466	0.466
Cragg-Uhl. R2	0.441	0.441	0.456	0.456
Cox-Snell R2	0.441	0.441	0.456	0.456
AIC	1074.896	1074.896	1077.028	1077.028
BIC	1109.931	1109.931	1116.442	1116.442
Overall Chi2	38.373 (0.000)		40.240 (0.001)	
Overall F-stat		8.521 (0.000)		8.039 (0.000)
N	66	66	66	66

Note: Point estimates calculated with OIM (unadjusted) and HW (Huber-White robust) standard errors are the same. The appropriate standard error is reported in parentheses. Depending of the formulation of the standard error, the chi-square statistic or F-statistic are calculated. The corresponding p-value is also reported.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-G8: Panel A: Tobit: onzn to nysi: Hypothesis test results

	(I) OIM se	(I) HW se	(II) OIM se	(II) HW se
Hypothesis A	1.1 (0.291)	1.1 (0.291)	3.5 (0.066)	3.5 (0.066)
Hypothesis B	10.9 (0.002)	10.9 (0.002)	4.3 (0.043)	4.3 (0.043)
Hypothesis C	1.8 (0.182)	1.8 (0.182)	1.7 (0.202)	1.7 (0.202)
Hypothesis D	0.9 (0.402)	0.9 (0.402)	1.8 (0.175)	1.8 (0.175)
Hypothesis E			1.1 (0.295)	1.1 (0.295)
Hypothesis F			0.0 (0.973)	0.0 (0.973)
Hypothesis G			1.2 (0.303)	1.2 (0.303)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G8: Panel B: Tobit: onzn to nysi: Hypothesis test results

	(III) OIM se	(III) HW se	(IV) OIM se	(IV) HW se
Hypothesis A	1.3 (0.264)	1.0 (0.323)	0.9 (0.336)	0.9 (0.355)
Hypothesis B	1.3 (0.254)	1.6 (0.218)	1.3 (0.264)	2.1 (0.157)
Hypothesis C	14.5 (0.000)	17.0 (0.000)	5.9 (0.018)	9.6 (0.003)
Hypothesis D	7.3 (0.001)	8.7 (0.000)	3.0 (0.059)	4.9 (0.011)
Hypothesis E			0.0 (0.897)	0.0 (0.845)
Hypothesis F			0.2 (0.665)	0.3 (0.605)
Hypothesis G			0.1 (0.907)	0.1 (0.874)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G8: Panel C: Tobit: onzn to nysi: Hypothesis test results

	(V) OIM se	(V) HW se	(VI) OIM se	(VI) HW se
Hypothesis A	2.7 (0.106)	4.6 (0.037)	4.4 (0.040)	6.0 (0.017)
Hypothesis B	1.8 (0.184)	5.7 (0.019)	0.6 (0.440)	1.2 (0.273)
Hypothesis C	6.6 (0.012)	21.2 (0.000)	4.6 (0.036)	9.3 (0.003)
Hypothesis D	3.4 (0.041)	14.0 (0.000)	2.8 (0.068)	4.7 (0.013)
Hypothesis E			0.7 (0.403)	1.3 (0.254)
Hypothesis F			0.0 (0.949)	0.0 (0.935)
Hypothesis G			0.8 (0.443)	2.7 (0.073)
Hypothesis J	4.4 (0.040)	1.3 (0.267)	4.4 (0.041)	1.3 (0.254)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G8: Panel D: Tobit: onzn to nysi: Hypothesis test results

	(VII) OIM se	(VII) HW se	(VIII) OIM se	(VIII) HW se
Hypothesis A	0.2 (0.630)	0.2 (0.626)	0.4 (0.511)	0.5 (0.462)
Hypothesis B	0.2 (0.622)	0.4 (0.513)	0.7 (0.401)	1.2 (0.274)
Hypothesis C	15.6 (0.000)	27.5 (0.000)	6.0 (0.018)	10.2 (0.002)
Hypothesis D	7.9 (0.001)	17.6 (0.000)	3.0 (0.059)	5.2 (0.009)
Hypothesis E			2.0 (0.162)	2.5 (0.122)
Hypothesis F			0.4 (0.529)	0.7 (0.414)
Hypothesis G			1.0 (0.365)	1.2 (0.298)
Hypothesis J	0.2 (0.635)	0.1 (0.790)	0.1 (0.764)	0.0 (0.864)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-G9: Panel A: Tobit: All paths jointly: Hypothesis test results

	(I)	(II)	(III)	(IV)
Hypothesis A	17.6 (0.002)	15.5 (0.004)	19.1 (0.001)	13.3 (0.010)
Hypothesis B	77.5 (0.000)	18.0 (0.001)	26.4 (0.000)	8.6 (0.071)
Hypothesis C	27.0 (0.000)	4.3 (0.373)	44.8 (0.000)	12.2 (0.016)
Hypothesis D	57.0 (0.000)	24.9 (0.002)	58.2 (0.000)	21.6 (0.006)
Hypothesis E		27.9 (0.000)		16.2 (0.003)
Hypothesis F		7.7 (0.104)		4.4 (0.351)
Hypothesis G		120.9 (0.000)		27.5 (0.001)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-G9: Panel B: Tobit: All paths jointly: Hypothesis test results

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	15.0 (0.005)	9.6 (0.047)	11.1 (0.025)	13.4 (0.009)
Hypothesis B	38.5 (0.000)	5.8 (0.218)	18.9 (0.001)	13.3 (0.010)
Hypothesis C	27.0 (0.000)	9.8 (0.043)	60.1 (0.000)	20.7 (0.000)
Hypothesis D	57.0 (0.000)	22.3 (0.004)	82.6 (0.000)	26.6 (0.001)
Hypothesis E		4.2 (0.381)		20.8 (0.000)
Hypothesis F		3.3 (0.516)		31.5 (0.000)
Hypothesis G		18.0 (0.022)		31.7 (0.000)
Hypothesis J	14.5 (0.006)	12.0 (0.019)	4.1 (0.389)	0.9 (0.919)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-G10: Panel A: 90% confidence intervals for MCP: misi to onzn

Model	OIM Lower	OIM Point	OIM Upper	HW Lower	HW Point	HW Upper
(I)	1.377	1.924	2.471	1.123	1.924	2.724
(II)	0.757	1.406	2.054	0.468	1.406	2.344
(III)	0.431	1.105	1.779	0.391	1.105	1.819
(IV)	-0.056	0.686	1.428	-0.095	0.686	1.467
(V)	1.109	1.661	2.213	0.838	1.661	2.484
(VI)	0.101	0.802	1.502	-0.141	0.802	1.745
(VII)	0.330	1.070	1.809	0.256	1.070	1.884
(VIII)	-1.663	-0.705	0.253	-1.568	-0.705	0.158

Table V-G10: Panel B: 90% confidence intervals for MCP: nysi to onzn

Model	OIM Lower	OIM Point	OIM Upper	HW Lower	HW Point	HW Upper
(I)	-1.940	1.033	4.006	-0.084	1.033	2.949
(II)	-0.836	2.350	5.537	0.098	2.350	4.602
(III)	-5.499	-2.457	0.585	-5.114	-2.457	0.200
(IV)	-4.314	-1.179	1.956	-4.037	-1.179	1.679
(V)	-2.669	-0.053	2.564	-2.243	-0.053	2.137
(VI)	-1.080	2.552	6.184	-0.816	2.552	5.919
(VII)	-4.022	-0.615	2.792	-3.544	-0.615	2.315
(VIII)	-9.530	-2.467	4.596	-7.889	-2.467	2.955

Table V-G10: Panel C: 90% confidence intervals for MCP: onzn to misi

Model	OIM Lower	OIM Point	OIM Upper	HW Lower	HW Point	HW Upper
(I)	0.400	0.619	0.837	0.400	0.619	0.837
(II)	-0.131	0.658	1.447	-0.131	0.658	1.447
(III)	0.277	0.527	0.777	0.342	0.527	0.713
(IV)	-0.023	0.838	1.700	0.177	0.838	1.500
(V)	0.359	0.688	1.017	0.457	0.688	0.919
(VI)	-0.169	0.696	1.561	-0.070	0.696	1.461
(VII)	0.011	0.374	0.737	0.204	0.374	0.545
(VIII)	0.238	1.361	2.483	0.666	1.361	2.056

Table V-G10: Panel D: 90% confidence intervals for MCP: onzn to nysi

Model	OIM Lower	OIM Point	OIM Upper	HW Lower	HW Point	HW Upper
(I)	0.351	0.710	1.068	0.351	0.710	1.068
(II)	0.118	0.616	1.113	0.118	0.616	1.113
(III)	-0.115	0.232	0.569	-0.079	0.232	0.543
(IV)	-0.153	0.316	0.785	-0.052	0.316	0.685
(V)	-0.084	0.343	0.769	0.104	0.343	0.581
(VI)	-0.305	0.266	0.837	-0.136	0.266	0.668
(VII)	-0.265	0.112	0.488	-0.172	0.112	0.395
(VIII)	-0.251	0.257	0.765	-0.133	0.257	0.647

Appendix V-H: Estimation results for path-by-path, two-stage analysis with ST FTR data

Table V-H1: Panel A: First-stage: misi to onzn: Probit estimates

	Coefficient
Global adjustment	0.0046 (0.0010)****
MacKinnon R2	0.228
McK.-Zav. R2	0.393
Cragg-Uhl. R2	0.355
Cox-Snell R2	0.262
AIC	92.449
BIC	97.358
Linktest	-0.412
Overall Chi2	26.078 (0.000)
N	86

Note: Standard error of the coefficient estimate associated with global adjustment is unadjusted. For Linktest, the reported value is the t-statistic associated with the squared term. P-value associated with chi-square statistic is reported in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H1: Panel B: First-stage: nysi to onzn: Probit estimates

	Coefficient
GAM	0.0035 (0.0012)***
MacKinnon R2	0.116
McK.-Zav. R2	0.271
Cragg-Uhl. R2	0.182
Cox-Snell R2	0.123
AIC	90.471
BIC	95.380
Linktest	-0.083
Overall Chi2	11.334 (0.001)
N	86

Note: Standard error of the coefficient estimate associated with GAM is unadjusted. For Linktest, the reported value is the t-statistic associated with the squared term. P-value associated with chi-square statistic is reported in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H1: Panel C: First-stage: onzn to misi: Probit estimates

	Coefficient
PD3-HOEP Difference	-0.1180 (0.0296)****
MacKinnon R2	0.183
McK.-Zav. R2	0.352
Cragg-Uhl. R2	0.291
Cox-Snell R2	0.212
AIC	95.908
BIC	100.817
Linktest	0.705
Overall Chi2	20.526 (0.000)
N	86

Note: Standard error of the coefficient estimate associated with PD3-HOEP difference is unadjusted. For Linktest, the reported value is the t-statistic associated with the squared term. P-value associated with chi-square statistic is reported in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H1: Panel D: First-stage: onzn to nysi: Probit estimates

	Coefficient
HDD PosDev Detroit	-0.0083 (0.0045)*
MacKinnon R2	0.062
McK.-Zav. R2	0.123
Cragg-Uhl. R2	0.084
Cox-Snell R2	0.041
AIC	58.059
BIC	62.968
Linktest	-1.120
Overall Chi2	3.593 (0.058)
N	86

Note: Standard error of the coefficient estimate associated with HDD PosDev Detroit is unadjusted. For Linktest, the reported value is the t-statistic associated with the squared term. P-value associated with chi-square statistic is reported in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H2: Consistency test of first-stage probit estimates

	misi to onzn	nysi to onzn	onzn to misi	onzn to nysi
Observed	0.384	0.744	0.360	0.105
Predicted	0.383	0.743	0.363	0.104

Table V-H3: Panel A: Second-stage: misi to onzn: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	0.694 (0.314)**	0.694 (0.436)	0.039 (0.362)	0.039 (0.424)
Inverse Mills ratio	1046.062 (395.007)***	1046.062 (553.211)*	1234.514 (382.448)***	1234.514 (566.648)**
1 / t			-4924.309 (2084.264)**	-4924.309 (3070.782)
MCP / t			9.550 (3.056)***	9.550 (5.804)
Constant	-860.623 (372.136)**	-860.623 (465.044)*	-884.078 (352.466)**	-884.078 (483.265)*
R-square	0.353		0.437	
Adj. R-square	0.335		0.404	
AIC	1266.608		1260.386	
BIC	1273.520		1271.907	
Root MSE	1235.681		1169.812	
Overall F-stat	19.385 (0.000)	7.185 (0.001)	13.370 (0.000)	5.179 (0.001)
N	74	74	74	74
Condition No.	6.97		8.54	
Mean VIF	1.94		3.56	
BP, standard	0.000		0.000	
BP, N*R2	0.004		0.000	
BP, F-stat	0.004		0.000	
White's test	0.032		0.000	
DW test	1.20		1.31	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	3.69	2.52	4.40	3.56
RESET test	0.001		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the

appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H3: Panel B: Second-stage: misi to onzn: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	0.478 (0.349)	0.478 (0.461)	-0.147 (0.388)	-0.147 (0.437)
HDD PosDev onzn	-1.721 (1.533)	-1.721 (1.394)	-0.729 (1.498)	-0.729 (1.167)
HDD NegDev onzn	6.214 (6.390)	6.214 (3.769)	2.803 (6.125)	2.803 (5.484)
CDD PosDev onzn	-25.921 (13.560)*	-25.921 (17.896)	-29.825 (12.826)**	-29.825 (15.486)*
CDD NegDev onzn	-51.865 (22.727)**	-51.865 (21.045)**	-53.355 (21.480)**	-53.355 (21.175)**
HDD PosDev misi	9.208 (6.078)	9.208 (14.230)	3.942 (5.996)	3.942 (9.658)
HDD NegDev misi	-12.048 (9.013)	-12.048 (5.114)**	-7.260 (8.624)	-7.260 (6.749)
CDD PosDev misi	46.765 (17.508)***	46.765 (19.892)**	50.885 (16.610)***	50.885 (18.619)***
CDD NegDev misi	34.788 (23.647)	34.788 (20.626)*	43.157 (22.422)*	43.157 (19.950)**
Natural gas price	2756.108 (1207.894)**	2756.108 (1146.916)**	1923.722 (1168.979)	1923.722 (1302.834)
Natural gas capacity ratio	30710.586 (14092.072)**	30710.586 (11236.980)***	25964.961 (13371.640)*	25964.961 (13028.821)*
NG price * NG capacity ratio	-6159.917 (2639.903)**	-6159.917 (2506.837)**	-4117.399 (2576.946)	-4117.399 (2904.283)
Risk-free	-267.270 (146.143)*	-267.270 (111.651)**	-193.209 (142.267)	-193.209 (126.692)
Inverse Mills ratio	1702.234 (738.234)**	1702.234 (1232.351)	1997.297 (708.663)***	1997.297 (1055.709)*
1 / t			-4129.128	-4129.128

			(1930.673)**	(2835.398)
MCP / t			9.704 (3.174)***	9.704 (6.405)
Constant			-13807.253 (6544.048)**	-13807.253 (6254.812)**
R-square	0.591		0.650	
Adj. R-square	0.494		0.551	
AIC	1256.729		1249.221	
BIC	1291.290		1288.390	
Root MSE	1078.186		1014.875	
Overall F-stat	6.084 (0.000)	2.900 (0.002)	6.608 (0.000)	3.816 (0.000)
N	74	74	74	74
Condition No.	330.20		347.34	
Mean VIF	46.98		44.29	
BP, standard	0.000		0.000	
BP, N*R2	0.002		0.000	
BP, F-stat	0.002		0.000	
White's test	0.445		0.445	
DW test	1.78		2.01	
Skew-kurt test	0.000	0.000	0.002	0.002
Linktest	5.58	6.83	6.73	5.40
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H3: Panel C: Second-stage: misi to onzn: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	0.597 (0.325)*	0.597 (0.432)	-0.801 (0.383)**	-0.801 (0.506)
Lag of Profit	0.358 (0.115)***	0.358 (0.148)**	0.326 (0.097)***	0.326 (0.161)**
Inverse Mills ratio	949.904 (412.950)**	949.904 (494.710)*	1518.509 (366.550)****	1518.509 (557.119)***
1 / t			-30646.384 (6895.084)****	-30646.384 (12156.732)**
MCP / t			30.995 (6.216)****	30.995 (11.597)***
Constant	-709.349 (387.516)*	-709.349 (391.487)*	-458.640 (335.379)	-458.640 (390.823)
R-square	0.450		0.621	
Adj. R-square	0.423		0.590	
AIC	1127.771		1107.051	
BIC	1136.530		1120.189	
Root MSE	1206.450		1016.944	
Overall F-stat	16.877 (0.000)	11.428 (0.000)	19.704 (0.000)	11.500 (0.000)
N	66	66	66	66
Condition No.	7.20		15.35	
Mean VIF	1.72		9.79	
BP, standard	0.000		0.000	
BP, N*R2	0.080		0.000	
BP, F-stat	0.082		0.000	
White's test	0.615		0.000	
Skew-kurt test	0.000	0.000	0.003	0.003
Linktest	1.41	1.18	3.60	3.89
RESET test	0.021		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H3: Panel D: Second-stage: misi to onzn: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	0.540 (0.373)	0.540 (0.468)	-1.275 (0.469)***	-1.275 (0.591)**
HDD PosDev onzn	-1.526 (1.567)	-1.526 (1.333)	-1.118 (1.330)	-1.118 (1.131)
HDD NegDev onzn	2.379 (6.789)	2.379 (4.073)	2.264 (5.669)	2.264 (4.748)
CDD PosDev onzn	-29.742 (14.468)**	-29.742 (18.175)	-30.146 (11.893)**	-30.146 (16.275)*
CDD NegDev onzn	-22.174 (26.992)	-22.174 (19.718)	-56.624 (23.229)**	-56.624 (28.786)*
HDD PosDev misi	16.625 (6.978)**	16.625 (16.837)	1.521 (6.460)	1.521 (6.986)
HDD NegDev misi	-5.003 (9.868)	-5.003 (6.227)	-2.842 (8.144)	-2.842 (7.360)
CDD PosDev misi	44.628 (18.966)**	44.628 (20.990)**	48.205 (15.712)***	48.205 (19.264)**
CDD NegDev misi	15.749 (26.088)	15.749 (16.688)	46.533 (22.271)**	46.533 (21.894)**
Natural gas price	1404.259 (1431.854)	1404.259 (1241.566)	2635.572 (1232.119)**	2635.572 (1582.468)
Natural gas capacity ratio	18372.512 (15858.566)	18372.512 (11388.158)	28189.625 (13235.624)**	28189.625 (14584.072)*
NG price * NG capacity ratio	-3512.851 (3050.482)	-3512.851 (2631.763)	-5861.887 (2651.139)**	-5861.887 (3400.750)*
Risk-free	-245.663 (165.582)	-245.663 (133.032)*	-234.701 (138.249)*	-234.701 (140.614)
Lag of Profit	0.257 (0.128)*	0.257 (0.133)*	0.137 (0.108)	0.137 (0.167)
Inverse Mills ratio	1972.263 (862.339)**	1972.263 (1216.242)	2416.188 (716.497)***	2416.188 (971.166)**
1 / t			-34786.751 (7645.645)****	-34786.751 (11527.284)***
MCP / t			33.620 (6.683)****	33.620 (10.862)***
Constant	-8744.794 (7826.979)	-8744.794 (5559.866)	-13668.739 (6503.952)**	-13668.739 (6896.542)**

R-square	0.641		0.767	
Adj. R-square	0.533		0.685	
AIC	1123.589		1098.953	
BIC	1158.623		1138.367	
Root MSE	1085.167		891.554	
Overall F-stat	5.948 (0.000)	4.860 (0.000)	9.309 (0.000)	7.461 (0.000)
N	66	66	66	66
Condition No.	359.23		347.34	
Mean VIF	50.98		44.29	
BP, standard	0.000		0.000	
BP, N*R2	0.002		0.000	
BP, F-stat	0.002		0.000	
White's test	0.442		0.442	
Skew-kurt test	0.000	0.000	0.729	0.729
Linktest	4.48	6.76	6.48	5.21
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H4: Panel A: Second-stage: misi to onzn: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	5.3 (0.024)	3.4 (0.068)	6.3 (0.014)	3.3 (0.072)
Hypothesis B	4.9 (0.031)	2.5 (0.116)	0.0 (0.915)	0.0 (0.927)
Hypothesis C	0.9 (0.333)	0.5 (0.485)	7.0 (0.010)	5.1 (0.026)
Hypothesis D	2.7 (0.074)	1.7 (0.188)	5.2 (0.008)	3.8 (0.028)
Hypothesis E			5.6 (0.021)	2.6 (0.113)
Hypothesis F			9.8 (0.003)	2.7 (0.104)
Hypothesis G			5.1 (0.009)	1.4 (0.265)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H4: Panel B: Second-stage: misi to onzn: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	4.8 (0.033)	7.4 (0.009)	4.5 (0.039)	4.9 (0.031)
Hypothesis B	1.9 (0.175)	1.1 (0.304)	0.1 (0.706)	0.1 (0.738)
Hypothesis C	2.2 (0.140)	1.3 (0.262)	8.8 (0.004)	6.9 (0.011)
Hypothesis D	2.7 (0.077)	3.8 (0.027)	5.4 (0.007)	4.7 (0.013)
Hypothesis E			4.6 (0.037)	2.1 (0.151)
Hypothesis F			9.3 (0.003)	2.3 (0.135)
Hypothesis G			4.8 (0.012)	1.2 (0.323)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H4: Panel C: Second-stage: misi to onzn: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	3.4 (0.072)	3.3 (0.075)	1.9 (0.177)	1.4 (0.245)
Hypothesis B	3.4 (0.071)	1.9 (0.172)	4.4 (0.041)	2.5 (0.119)
Hypothesis C	1.5 (0.219)	0.9 (0.355)	22.1 (0.000)	12.6 (0.001)
Hypothesis D	1.9 (0.154)	1.7 (0.195)	11.4 (0.000)	6.6 (0.003)
Hypothesis E			19.8 (0.000)	6.4 (0.014)
Hypothesis F			24.5 (0.000)	7.1 (0.010)
Hypothesis G			13.6 (0.000)	4.2 (0.019)
Hypothesis J	9.8 (0.003)	5.8 (0.019)	11.2 (0.001)	4.1 (0.047)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H4: Panel D: Second-stage: misi to onzn: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	1.2 (0.269)	2.5 (0.122)	4.4 (0.041)	3.9 (0.053)
Hypothesis B	2.1 (0.154)	1.3 (0.254)	7.9 (0.009)	4.7 (0.036)
Hypothesis C	1.5 (0.223)	1.0 (0.330)	23.5 (0.000)	14.8 (0.000)
Hypothesis D	1.0 (0.365)	1.3 (0.279)	11.9 (0.000)	7.5 (0.002)
Hypothesis E			20.7 (0.000)	9.1 (0.004)
Hypothesis F			25.3 (0.000)	9.6 (0.003)
Hypothesis G			13.0 (0.000)	4.8 (0.013)
Hypothesis J	4.0 (0.050)	3.8 (0.058)	1.6 (0.214)	0.7 (0.416)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H5: Panel A: Second-stage: nysi to onzn: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	-1.007 (0.580)*	-1.007 (0.580)*	-0.726 (0.617)	-0.726 (0.720)
Inverse Mills ratio	1517.868 (391.607)****	1517.868 (845.776)*	1213.501 (326.884)****	1213.501 (931.267)
1 / t			5194.037 (961.930)***	5194.037 (679.450)****
MCP / t			-10.207 (3.786)***	-10.207 (2.039)****
Constant	-351.529 (184.598)*	-351.529 (250.965)	-424.829 (152.060)***	-424.829 (266.860)
R-square	0.173		0.461	
Adj. R-square	0.150		0.431	
AIC	1207.715		1179.585	
BIC	1214.667		1191.172	
Root MSE	744.643		609.593	
Overall F-stat	7.553 (0.001)	1.636 (0.202)	14.994 (0.000)	34.938 (0.000)
N	75	75	75	75
Condition No.	4.75		5.92	
Mean VIF	1.17		2.72	
BP, standard	0.000		0.000	
BP, N*R2	0.004		0.082	
BP, F-stat	0.004		0.084	
White's test	0.005		0.000	
DW test	1.24		1.36	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	3.98	2.16	1.68	0.94
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H5: Panel B: Second-stage: *nys* to *onzn*: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	-0.441 (0.964)	-0.441 (0.520)	-0.043 (0.700)	-0.043 (0.485)
HDD PosDev onzn	-0.568 (0.995)	-0.568 (0.689)	0.130 (0.785)	0.130 (0.260)
HDD NegDev onzn	-1.520 (4.343)	-1.520 (3.110)	-1.927 (3.793)	-1.927 (2.923)
CDD PosDev onzn	-3.296 (6.440)	-3.296 (6.321)	-0.335 (4.994)	-0.335 (5.870)
CDD NegDev onzn	-1.405 (9.601)	-1.405 (5.462)	2.767 (7.467)	2.767 (3.161)
HDD PosDev misi	-5.883 (4.317)	-5.883 (4.130)	-2.385 (3.635)	-2.385 (3.409)
HDD NegDev misi	5.068 (6.502)	5.068 (4.872)	5.232 (5.509)	5.232 (4.470)
CDD PosDev misi	6.083 (7.796)	6.083 (7.531)	7.510 (6.022)	7.510 (6.789)
CDD NegDev misi	1.785 (8.788)	1.785 (3.079)	3.677 (6.786)	3.677 (2.437)
Natural gas price	-1028.972 (746.826)	-1028.972 (849.772)	-983.206 (598.819)	-983.206 (654.684)
Natural gas capacity ratio	-9848.419 (8719.557)	-9848.419 (9925.152)	-5645.963 (6959.992)	-5645.963 (6959.992)
NG price * NG capacity ratio	1755.715 (1614.866)	1755.715 (1649.005)	1903.744 (1315.329)	1903.744 (1236.800)
Risk-free	-182.611 (107.740)*	-182.611 (115.602)	-85.716 (85.773)	-85.716 (77.532)
Inverse Mills ratio	3315.292 (876.708)****	3315.292 (1677.505)*	2826.059 (680.872)****	2826.059 (1736.799)
1 / t			5368.705 (945.708)****	5368.705 (560.981)****
MCP / t			-8.626 (4.373)*	-8.626 (2.687)***
Constant	5366.785 (4272.199)	5366.785 (5289.758)	2316.289 (3395.641)	2316.289 (2907.854)

R-square	0.373		0.639	
Adj. R-square	0.227		0.540	
AIC	1210.987		1173.521	
BIC	1245.749		1212.918	
Root MSE	710.437		548.064	
Overall F-stat	2.550 (0.006)	0.614 (0.843)	6.425 (0.000)	125.717 (0.000)
N	75	75	75	75
Condition No.	303.20		323.86	
Mean VIF	40.75		39.65	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.446		0.446	
DW test	1.57		1.92	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	6.00	5.80	2.49	1.44
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H5: Panel C: Second-stage: *nysi* to *onzn*: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	-0.975 (0.513)*	-0.975 (0.630)	-0.895 (0.830)	-0.895 (0.881)
Lag of Profit	0.159 (0.089)	0.159 (0.099)	0.173 (0.103)*	0.173 (0.115)
Inverse Mills ratio	1265.068 (347.248)****	1265.068 (819.597)	1357.025 (414.806)***	1357.025 (923.809)
1 / t			-3730.818 (4262.608)	-3730.818 (2942.848)
MCP / t			6.085 (9.651)	6.085 (6.495)
Constant	-307.036 (159.611)*	-307.036 (241.402)	-254.222 (168.383)	-254.222 (218.480)
R-square	0.274		0.288	
Adj. R-square	0.240		0.231	
AIC	1065.328		1068.008	
BIC	1074.206		1081.325	
Root MSE	593.384		597.057	
Overall F-stat	8.060 (0.000)	1.422 (0.245)	5.019 (0.001)	0.884 (0.497)
N	68	68	68	68
Condition No.	5.12		15.27	
Mean VIF	1.23		10.71	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.000		0.000	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	2.40	1.32	1.86	1.09
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H5: Panel D: Second-stage: *nysi* to *onzn*: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	-0.482 (0.606)	-0.482 (0.434)	-1.017 (1.112)	-1.017 (1.101)
HDD PosDev onzn	0.160 (0.791)	0.160 (0.222)	0.272 (0.835)	0.272 (0.399)
HDD NegDev onzn	-1.128 (3.771)	-1.128 (2.581)	-1.598 (4.046)	-1.598 (3.020)
CDD PosDev onzn	-1.994 (5.689)	-1.994 (8.165)	-2.886 (6.062)	-2.886 (9.698)
CDD NegDev onzn	4.452 (9.110)	4.452 (3.963)	4.276 (9.403)	4.276 (4.598)
HDD PosDev misi	-1.564 (3.606)	-1.564 (2.556)	-3.157 (4.583)	-3.157 (4.194)
HDD NegDev misi	5.134 (5.555)	5.134 (3.920)	5.669 (5.965)	5.669 (5.104)
CDD PosDev misi	3.103 (6.985)	3.103 (6.947)	4.328 (7.530)	4.328 (8.678)
CDD NegDev misi	2.377 (8.014)	2.377 (2.913)	3.068 (8.267)	3.068 (3.996)
Natural gas price	-976.490 (663.530)	-976.490 (806.402)	-973.718 (798.024)	-973.718 (1049.959)
Natural gas capacity ratio	-6018.118 (7543.997)	-6018.118 (5875.113)	-6030.062 (8089.178)	-6030.062 (7209.173)
NG price * NG capacity ratio	1691.649 (1426.731)	1691.649 (1428.996)	1721.543 (1751.757)	1721.543 (2038.260)
Risk-free	-126.913 (89.852)	-126.913 (77.255)	-138.838 (95.124)	-138.838 (85.963)
Lag of Profit	0.030 (0.106)	0.030 (0.138)	-0.023 (0.143)	-0.023 (0.234)
Inverse Mills ratio	3651.663 (890.755)****	3651.663 (2503.612)	3806.967 (944.480)****	3806.967 (2766.577)
1 / t			-1719.648 (6465.815)	-1719.648 (3676.827)
MCP / t			5.849 (13.404)	5.849 (8.253)
Constant	3011.066 (3702.546)	3011.066 (3040.086)	2958.908 (3847.667)	2958.908 (3388.364)

R-square	0.488		0.492	
Adj. R-square	0.341		0.320	
AIC	1065.538		1069.040	
BIC	1101.050		1108.991	
Root MSE	552.658		561.541	
Overall F-stat	3.310 (0.001)	0.562 (0.890)	2.851 (0.002)	0.503 (0.939)
N	68	68	68	68
Condition No.	326.86		323.86	
Mean VIF	43.12		39.65	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.443		0.443	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	8.83	5.18	9.92	6.36
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H6: Panel A: Second-stage: nysi to onzn: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	3.6 (0.061)	2.0 (0.166)	7.8 (0.007)	2.5 (0.116)
Hypothesis B	3.0 (0.087)	3.0 (0.087)	1.4 (0.243)	1.0 (0.317)
Hypothesis C	12.0 (0.001)	12.0 (0.001)	7.8 (0.007)	5.7 (0.019)
Hypothesis D	8.3 (0.001)	8.4 (0.001)	8.8 (0.000)	3.0 (0.058)
Hypothesis E			29.2 (0.009)	58.4 (0.000)
Hypothesis F			7.3 (0.009)	25.1 (0.000)
Hypothesis G			18.7 (0.000)	43.1 (0.000)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H6: Panel B: Second-stage: nysi to onzn: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	1.6 (0.214)	1.0 (0.314)	0.5 (0.498)	0.6 (0.429)
Hypothesis B	0.4 (0.527)	0.7 (0.400)	0.0 (0.951)	0.0 (0.929)
Hypothesis C	4.3 (0.042)	7.7 (0.007)	2.2 (0.142)	4.6 (0.036)
Hypothesis D	3.2 (0.047)	4.0 (0.023)	1.3 (0.287)	2.5 (0.093)
Hypothesis E			32.2 (0.000)	91.6 (0.000)
Hypothesis F			3.9 (0.053)	10.3 (0.002)
Hypothesis G			21.4 (0.000)	85.8 (0.000)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H6: Panel C: Second-stage: nysi to onzn: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	3.7 (0.059)	1.6 (0.208)	2.3 (0.136)	1.4 (0.249)
Hypothesis B	3.6 (0.062)	2.4 (0.126)	1.2 (0.285)	1.0 (0.313)
Hypothesis C	14.8 (0.000)	9.8 (0.003)	5.2 (0.026)	4.6 (0.035)
Hypothesis D	9.5 (0.000)	7.6 (0.001)	4.0 (0.023)	2.5 (0.092)
Hypothesis E			0.8 (0.385)	1.6 (0.210)
Hypothesis F			0.4 (0.531)	0.9 (0.352)
Hypothesis G			0.6 (0.548)	1.2 (0.304)
Hypothesis J	3.2 (0.080)	2.6 (0.115)	2.8 (0.098)	2.3 (0.137)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H6: Panel D: Second-stage: nysi to onzn: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	0.7 (0.420)	1.0 (0.327)	0.6 (0.446)	0.8 (0.387)
Hypothesis B	0.6 (0.430)	1.2 (0.272)	0.8 (0.365)	0.9 (0.360)
Hypothesis C	6.0 (0.018)	11.6 (0.001)	3.3 (0.076)	3.4 (0.073)
Hypothesis D	3.7 (0.031)	5.8 (0.005)	2.2 (0.121)	1.7 (0.073)
Hypothesis E			0.1 (0.791)	0.2 (0.642)
Hypothesis F			0.2 (0.664)	0.2 (0.482)
Hypothesis G			0.2 (0.833)	0.3 (0.773)
Hypothesis J	0.1 (0.781)	0.0 (0.831)	0.0 (0.875)	0.0 (0.924)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H7: Panel A: Second-stage: onzn to misi: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	0.476 (0.099)****	0.476 (0.056)****	0.739 (0.297)**	0.739 (0.129)****
Inverse Mills ratio	110.519 (191.831)	110.519 (118.560)	54.666 (201.638)	54.666 (126.173)
1 / t			-463.444 (737.279)	-463.444 (313.779)
MCP / t			-15.625 (16.393)	-15.625 (6.336)**
Constant	110.263 (222.983)	110.263 (135.848)	222.355 (252.127)	222.355 (176.301)
R-square	0.273		0.289	
Adj. R-square	0.253		0.247	
AIC	1200.513		1202.937	
BIC	1207.425		1214.458	
Root MSE	790.596		793.480	
Overall F-stat	13.359 (0.000)	42.388 (0.000)	7.002 (0.000)	23.873 (0.000)
N	74	74	74	74
Condition No.	5.03		8.00	
Mean VIF	1.07		5.33	
BP, standard	0.933		0.653	
BP, N*R2	0.978		0.883	
BP, F-stat	0.978		0.885	
White's test	0.927		0.970	
DW test	1.46		1.49	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-0.18	-0.20	-0.03	-0.03
RESET test	0.901		0.687	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H7: Panel B: Second-stage: onzn to misi: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	0.458 (0.115)****	0.458 (0.088)****	0.638 (0.387)	0.638 (0.167)****
HDD PosDev onzn	-0.313 (1.099)	-0.313 (0.760)	-0.632 (1.145)	-0.632 (0.874)
HDD NegDev onzn	1.682 (4.715)	1.682 (8.272)	2.003 (4.771)	2.003 (8.297)
CDD PosDev onzn	6.450 (9.861)	6.450 (5.224)	6.961 (4.771)	6.961 (5.095)
CDD NegDev onzn	0.587 (17.273)	0.587 (13.620)	1.999 (18.160)	1.999 (13.123)
HDD PosDev misi	-4.437 (4.604)	-4.437 (4.848)	-4.586 (4.651)	-4.586 (5.015)
HDD NegDev misi	-2.563 (6.626)	-2.563 (7.480)	-2.742 (6.703)	-2.742 (7.466)
CDD PosDev misi	-17.323 (13.343)	-17.323 (5.430)***	-18.509 (13.663)	-18.509 (6.631)***
CDD NegDev misi	8.510 (17.473)	8.510 (18.170)	6.982 (17.653)	6.982 (18.084)
Natural gas price	-1766.685 (876.979)**	-1766.685 (1100.574)	-1666.752 (894.770)*	-1666.752 (1121.494)
Natural gas capacity ratio	-17408.150 (10048.928)*	-17408.150 (12361.014)	-17998.722 (10148.891)*	-17998.722 (13166.401)
NG price * NG capacity ratio	3856.419 (1939.820)*	3856.419 (2383.865)	3571.713 (1980.179)*	3571.713 (2407.578)
Risk-free	-160.609 (110.617)	-160.609 (139.442)	-187.366 (114.205)	-187.366 (151.431)
Inverse Mills ratio	-629.583 (355.612)*	-629.583 (293.632)**	-632.509 (382.533)	-632.509 (339.217)*
1 / t			-933.861 (923.527)	-933.861 (814.855)
MCP / t			-10.812 (23.129)	-10.812 (9.071)
Constant	9639.226 (4980.715)*	9639.226 (6662.977)	10244.073 (5082.514)**	10244.073 (7216.242)

R-square	0.393		0.406	
Adj. R-square	0.249		0.239	
AIC	1211.211		1213.616	
BIC	1245.772		1252.785	
Root MSE	792.728		797.873	
Overall F-stat	2.728 (0.004)	11.743 (0.000)	2.434 (0.007)	12.104 (0.000)
N	74	74	74	74
Condition No.	314.18		325.34	
Mean VIF	45.68		43.23	
BP, standard	0.001		0.000	
BP, N*R2	0.279		0.190	
BP, F-stat	0.285		0.195	
White's test	0.441		0.445	
DW test	1.62		1.67	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	0.99	0.99	1.06	1.04
RESET test	0.263		0.182	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H7: Panel C: Second-stage: onzn to misi: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	0.452 (0.146)***	0.452 (0.093)****	0.677 (0.328)**	0.677 (0.130)****
Lag of Profit	0.138 (0.136)	0.138 (0.128)	0.114 (0.139)	0.114 (0.130)
Inverse Mills ratio	163.122 (209.545)	163.122 (119.835)	68.349 (239.690)	68.349 (146.701)
1 / t			-1050.379 (1543.312)	-1050.379 (836.701)
MCP / t			-13.983 (17.641)	-13.983 (5.584)**
Constant	46.708 (240.703)	46.708 (133.858)	256.789 (317.340)	256.789 (234.954)
R-square	0.165		0.184	
Adj. R-square	0.125		0.116	
AIC	1078.844		1081.372	
BIC	1087.603		1094.510	
Root MSE	832.788		837.166	
Overall F-stat	4.095 (0.010)	24.932 (0.000)	2.702 (0.029)	14.720 (0.000)
N	66	66	66	66
Condition No.	5.03		8.00	
Mean VIF	1.07		5.33	
BP, standard	0.802		0.586	
BP, N*R2	0.922		0.854	
BP, F-stat	0.934		0.857	
White's test	0.980			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	0.02	0.03	0.13	0.27
RESET test	0.809		0.755	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H7: Panel D: Second-stage: onzn to misi: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	0.294 (0.174)*	0.294 (0.137)**	0.699 (0.491)	0.699 (0.259)***
HDD PosDev onzn	-0.447 (1.168)	-0.447 (0.873)	-1.140 (1.223)	-1.140 (1.016)
HDD NegDev onzn	0.050 (5.167)	0.050 (9.577)	1.704 (5.206)	1.704 (9.498)
CDD PosDev onzn	4.327 (10.884)	4.327 (6.246)	6.457 (10.984)	6.457 (6.741)
CDD NegDev onzn	9.472 (21.184)	9.472 (16.081)	23.445 (27.157)	23.445 (12.712)*
HDD PosDev misi	-2.893 (5.494)	-2.893 (4.626)	-2.480 (5.446)	-2.480 (4.510)
HDD NegDev misi	-0.363 (7.503)	-0.363 (9.114)	-2.051 (7.536)	-2.051 (9.035)
CDD PosDev misi	-17.430 (15.199)	-17.430 (7.232)**	-20.643 (15.507)	-20.643 (10.187)**
CDD NegDev misi	2.612 (19.943)	2.612 (19.989)	-6.673 (21.448)	-6.673 (17.903)
Natural gas price	-2464.782 (1003.803)**	-2464.782 (1363.339)*	-1789.980 (1075.182)	-1789.980 (1328.595)
Natural gas capacity ratio	-24708.515 (11466.225)**	-24708.515 (15108.329)	-20665.561 (11613.589)*	-20665.561 (15244.385)
NG price * NG capacity ratio	5343.397 (2207.802)**	5343.397 (2946.203)*	3710.522 (2388.667)	3710.522 (2886.609)
Risk-free	-231.387 (126.697)*	-231.387 (177.423)	-280.418 (129.560)**	-280.418 (184.698)
Lag of Profit	-0.007 (0.154)	-0.007 (0.123)	-0.053 (0.155)	-0.053 (0.138)
Inverse Mills ratio	-703.808 (407.653)*	-703.808 (368.355)*	-786.120 (468.939)	-786.120 (514.551)
1 / t			-3282.184 (2157.490)	-3282.184 (2492.512)
MCP / t			-28.728 (33.245)	-28.728 (12.807)**
Constant	13532.222 (5713.957)**	13532.222 (8170.247)	12474.496 (5763.928)**	12474.496 (8288.325)

R-square	0.333		0.373	
Adj. R-square	0.132		0.151	
AIC	1088.089		1087.997	
BIC	1123.123		1127.411	
Root MSE	829.273		820.541	
Overall F-stat	1.661 (0.091)	7.022 (0.000)	1.678 (0.081)	10.131 (0.000)
N	66	66	66	66
Condition No.	314.18		325.34	
Mean VIF	45.68		43.23	
BP, standard	0.000		0.000	
BP, N*R2	0.129		0.046	
BP, F-stat	0.133		0.046	
White's test	0.442			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	1.00	1.30	1.01	1.04
RESET test	0.527		0.020	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H8: Panel A: Second-stage: onzn to misi: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	0.2 (0.622)	0.7 (0.420)	0.8 (0.381)	1.6 (0.211)
Hypothesis B	23.1 (0.000)	73.1 (0.000)	6.2 (0.015)	32.9 (0.000)
Hypothesis C	28.0 (0.000)	88.8 (0.000)	0.8 (0.383)	4.1 (0.047)
Hypothesis D	14.4 (0.000)	45.1 (0.000)	0.9 (0.420)	4.2 (0.018)
Hypothesis E			0.4 (0.532)	2.2 (0.144)
Hypothesis F			0.9 (0.344)	6.1 (0.016)
Hypothesis G			0.7 (0.480)	3.2 (0.046)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H8: Panel B: Second-stage: onzn to misi: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	3.7 (0.058)	2.1 (0.153)	4.1 (0.049)	2.0 (0.161)
Hypothesis B	15.8 (0.000)	26.7 (0.000)	2.7 (0.105)	14.6 (0.000)
Hypothesis C	22.1 (0.000)	37.6 (0.000)	0.9 (0.354)	4.7 (0.034)
Hypothesis D	11.8 (0.000)	22.0 (0.000)	2.3 (0.110)	2.4 (0.100)
Hypothesis E			1.0 (0.316)	1.3 (0.257)
Hypothesis F			0.2 (0.642)	1.4 (0.238)
Hypothesis G			0.6 (0.541)	1.5 (0.227)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H8: Panel C: Second-stage: onzn to misi: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	0.1 (0.751)	0.3 (0.569)	0.7 (0.422)	1.2 (0.279)
Hypothesis B	9.6 (0.003)	23.5 (0.000)	4.3 (0.043)	27.2 (0.000)
Hypothesis C	14.1 (0.000)	34.7 (0.000)	1.0 (0.329)	6.2 (0.016)
Hypothesis D	7.2 (0.002)	17.5 (0.000)	0.8 (0.329)	3.8 (0.027)
Hypothesis E			0.5 (0.499)	1.6 (0.214)
Hypothesis F			0.6 (0.431)	6.3 (0.015)
Hypothesis G			0.7 (0.512)	3.3 (0.046)
Hypothesis J	1.0 (0.316)	1.2 (0.286)	0.7 (0.413)	0.8 (0.381)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H8: Panel D: Second-stage: onzn to misi: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	5.6 (0.022)	2.7 (0.104)	4.7 (0.035)	2.3 (0.139)
Hypothesis B	2.9 (0.097)	4.6 (0.037)	2.0 (0.160)	7.3 (0.010)
Hypothesis C	16.6 (0.000)	26.5 (0.000)	0.4 (0.543)	1.3 (0.252)
Hypothesis D	9.7 (0.000)	17.1 (0.000)	2.3 (0.107)	1.2 (0.324)
Hypothesis E			2.3 (0.135)	1.7 (0.030)
Hypothesis F			0.7 (0.392)	5.0 (0.030)
Hypothesis G			1.5 (0.226)	3.0 (0.059)
Hypothesis J	0.0 (0.962)	0.0 (0.952)	0.1 (0.736)	0.1 (0.705)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H9: Panel A: Second-stage: onzn to nysi: Estimates and diagnostic tests

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
MCP	0.643 (0.204)***	0.643 (0.142)****	0.708 (0.257)***	0.708 (0.151)****
Inverse Mills ratio	449.418 (640.493)	449.418 (420.865)	461.426 (648.665)	461.426 (441.721)
1 / t			-296.793 (1972.444)	-296.793 (899.610)
MCP / t			-5.111 (7.825)	-5.111 (4.745)
Constant	-326.303 (1175.503)	-326.303 (816.757)	-211.708 (1201.253)	-211.708 (866.636)
R-square	0.132		0.145	
Adj. R-square	0.107		0.095	
AIC	1291.488		1294.396	
BIC	1298.360		1305.848	
Root MSE	1647.078		1658.670	
Overall F-stat	5.329 (0.007)	12.569 (0.000)	2.884 (0.029)	11.199 (0.000)
N	73	73	73	73
Condition No.	13.76		16.16	
Mean VIF	1.00		1.62	
BP, standard	0.162		0.210	
BP, N*R2	0.662		0.702	
BP, F-stat	0.667		0.702	
White's test	0.802		0.993	
DW test	1.62		1.62	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	0.07	0.09	0.04	0.06
RESET test	0.460		0.785	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H9: Panel B: Second-stage: onzn to nysi: Estimates and diagnostic tests

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
MCP	0.158 (0.215)	0.158 (0.224)	0.224 (0.299)	0.224 (0.252)
HDD PosDev onzn	-1.823 (2.064)	-1.823 (1.146)	-1.527 (2.135)	-1.527 (1.084)
HDD NegDev onzn	-19.780 (10.071)*	-19.780 (10.536)*	-20.444 (10.656)*	-20.444 (10.636)*
CDD PosDev onzn	-17.974 (12.545)	-17.974 (8.836)**	-17.265 (12.712)	-17.265 (8.763)
CDD NegDev onzn	-1.860 (20.289)	-1.860 (16.695)	1.352 (21.023)	1.352 (17.515)*
HDD PosDev nysi	4.740 (13.063)	4.740 (10.562)	5.231 (13.547)	5.231 (11.017)
HDD NegDev nysi	-0.831 (13.814)	-0.831 (11.925)	0.577 (14.414)	0.577 (11.358)
CDD PosDev nysi	5.207 (15.814)	5.207 (8.482)	5.485 (15.620)	5.485 (8.929)
CDD NegDev nysi	42.627 (18.554)**	42.627 (20.327)**	43.083 (18.814)**	43.083 (20.472)**
Natural gas price	-3279.987 (1687.876)*	-3279.987 (1655.691)*	-3244.934 (1847.768)*	-3244.934 (1583.934)**
Natural gas capacity ratio	-34491.285 (20056.554)*	-34491.285 (18645.532)*	-32571.051 (21112.557)	-32571.051 (18074.576)*
NG price * NG capacity ratio	8556.643 (3789.794)**	8556.643 (3661.431)**	8583.913 (4148.304)**	8583.913 (3571.736)**
Risk-free	-179.532 (224.366)	-179.532 (200.464)	-148.762 (228.879)	-148.762 (198.005)
Inverse Mills ratio	-2092.215 (1406.046)	-2092.215 (1829.113)	-2028.467 (1421.413)	-2028.467 (1832.492)
1 / t			1820.124 (1982.197)	1820.124 (19421.492)
MCP / t			-2.595 (9.760)	-2.595 (7.656)
Constant	17884.560 (10754.643)	17884.560 (10726.633)	16375.429 (11269.345)	16375.429 (10600.817)

R-square	0.430		0.439	
Adj. R-square	0.292		0.279	
AIC	1284.809		1287.654	
BIC	1319.165		1326.591	
Root MSE	1466.522		1480.721	
Overall F-stat	3.124 (0.001)	5.446 (0.000)	2.738 (0.000)	5.039 (0.000)
N	73	73	73	73
Condition No.	342.30		380.96	
Mean VIF	45.79		46.89	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.445		0.445	
DW test	1.87		1.91	
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	4.69	2.78	4.46	2.58
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table V-H9: Panel C: Second-stage: onzn to nysi: Estimates and diagnostic tests

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
MCP	0.306 (0.246)	0.306 (0.123)**	0.307 (0.329)	0.307 (0.174)*
Lag of Profit	0.260 (0.130)**	0.260 (0.196)	0.262 (0.131)*	0.262 (0.192)
Inverse Mills ratio	247.149 (678.026)	247.149 (374.315)	276.640 (687.873)	276.640 (379.842)
1 / t			-1666.083 (4218.695)	-1666.083 (1929.052)
MCP / t			-1.954 (9.950)	-1.954 (5.607)
Constant	206.798 (1243.816)	206.798 (718.754)	308.031 (1272.326)	308.031 (807.090)
R-square	0.133		0.144	
Adj. R-square	0.091		0.073	
AIC	1167.650		1170.764	
BIC	1176.409		1183.902	
Root MSE	3.164		1647.860	
Overall F-stat	0.031 (0.000)	8.249 (0.000)	2.024 (0.088)	14.633 (0.000)
N	66	66	66	66
Condition No.	13.76		16.16	
Mean VIF	1.00		1.62	
BP, standard	0.000		0.000	
BP, N*R2	0.065		0.080	
BP, F-stat	0.067		0.082	
White's test	0.202			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	-3.47	-2.35	-2.52	-1.69
RESET test	0.003		0.006	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H9: Panel D: Second-stage: onzn to nysi: Estimates and diagnostic tests

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
MCP	0.049 (0.244)	0.049 (0.188)	0.165 (0.329)	0.165 (0.231)
HDD PosDev onzn	-1.276 (2.109)	-1.276 (1.034)	-0.827 (2.144)	-0.827 (0.997)
HDD NegDev onzn	-14.563 (10.495)	-14.563 (9.119)	-22.535 (11.660)*	-22.535 (11.286)*
CDD PosDev onzn	-17.283 (17.992)	-17.283 (9.298)*	-18.275 (12.941)	-18.275 (9.629)*
CDD NegDev onzn	-12.607 (24.518)	-12.607 (20.623)	-5.485 (26.287)	-5.485 (23.858)
HDD PosDev nysi	2.707 (13.707)	2.707 (10.746)	-0.833 (14.125)	-0.833 (10.317)
HDD NegDev nysi	-5.180 (14.577)	-5.180 (12.651)	6.952 (16.343)	6.952 (11.453)
CDD PosDev nysi	8.226 (15.651)	8.226 (8.988)	8.809 (15.546)	8.809 (9.970)
CDD NegDev nysi	54.097 (21.514)**	54.097 (22.465)**	55.865 (22.022)**	55.865 (22.686)**
Natural gas price	-2096.509 (1870.503)	-2096.509 (1432.292)	-3318.755 (2102.478)	-3318.755 (1553.890)**
Natural gas capacity ratio	-19789.383 (22252.914)	-19789.383 (15592.525)	-29381.256 (23443.817)	-29381.256 (15959.988)*
NG price * NG capacity ratio	5903.752 (4190.865)	5903.752 (3210.947)	8881.712 (4756.780)*	8881.712 (3772.905)**
Risk-free	-20.151 (247.141)	-20.151 (156.294)	-17.635 (245.575)	-17.635 (160.998)
Lag of Profit	0.066 (0.130)	0.066 (0.214)	0.038 (0.130)	0.038 (0.212)
Inverse Mills ratio	-1907.980 (1492.888)	-1907.980 (1907.105)	-1720.483 (1487.040)	-1720.483 (1894.371)
1 / t			7743.712 (4929.692)	7743.712 (3774.512)**
MCP / t			-5.013 (11.032)	-5.013 (8.097)
Constant	10267.455 (11952.134)	10267.455 (9286.099)	13318.474 (12261.561)	13318.474 (9348.759)

R-square	0.437		0.467	
Adj. R-square	0.268		0.278	
AIC	1163.152		1163.536	
BIC	1198.187		1202.950	
Root MSE	1464.416		1454.229	
Overall F-stat	2.586 (0.006)	5.529 (0.000)	2.473 (0.007)	6.612 (0.000)
N	66	66	66	66
Condition No.	312.30		380.96	
Mean VIF	45.79		46.89	
BP, standard	0.000		0.000	
BP, N*R2	0.000		0.000	
BP, F-stat	0.000		0.000	
White's test	0.442			
Skew-kurt test	0.000	0.000	0.000	0.000
Linktest	3.89	2.60	4.36	2.58
RESET test	0.000		0.000	

Note: Point estimates from OLS and Newey-West estimation approaches are the same. Unadjusted OLS and Newey-West standard errors are reported in parentheses in the appropriate column. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition Number, Mean VIF, and DW value, the reported values are un-normalised test statistics.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H10: Panel A: Second-stage: onzn to nysi: Hypothesis test results

	(I) OLS se	(I) NW se	(II) OLS se	(II) NW se
Hypothesis A	0.1 (0.782)	0.2 (0.691)	0.0 (0.861)	0.1 (0.808)
Hypothesis B	10.0 (0.002)	20.7 (0.000)	7.6 (0.007)	22.0 (0.000)
Hypothesis C	3.1 (0.085)	6.3 (0.014)	1.3 (0.260)	3.7 (0.058)
Hypothesis D	1.7 (0.199)	3.2 (0.047)	0.7 (0.497)	2.2 (0.114)
Hypothesis E			0.0 (0.881)	0.1 (0.742)
Hypothesis F			0.4 (0.516)	1.2 (0.285)
Hypothesis G			0.5 (0.601)	3.3 (0.042)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H10: Panel B: Second-stage: onzn to nysi: Hypothesis test results

	(III) OLS se	(III) NW se	(IV) OLS se	(IV) NW se
Hypothesis A	2.8 (0.102)	2.8 (0.101)	2.1 (0.152)	2.4 (0.128)
Hypothesis B	0.5 (0.466)	0.5 (0.484)	0.6 (0.456)	0.8 (0.378)
Hypothesis C	15.4 (0.000)	14.2 (0.000)	6.7 (0.012)	9.5 (0.003)
Hypothesis D	7.8 (0.001)	7.2 (0.002)	3.5 (0.039)	4.7 (0.012)
Hypothesis E			0.8 (0.362)	1.6 (0.206)
Hypothesis F			0.1 (0.791)	0.1 (0.736)
Hypothesis G			0.4 (0.642)	0.8 (0.437)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H10: Panel C: Second-stage: onzn to nysi: Hypothesis test results

	(V) OLS se	(V) NW se	(VI) OLS se	(VI) NW se
Hypothesis A	0.0 (0.868)	0.1 (0.775)	0.1 (0.810)	0.1 (0.704)
Hypothesis B	1.5 (0.218)	6.1 (0.016)	0.9 (0.354)	3.1 (0.082)
Hypothesis C	7.9 (0.006)	31.6 (0.000)	4.4 (0.039)	15.9 (0.000)
Hypothesis D	4.0 (0.023)	15.9 (0.000)	2.2 (0.116)	11.4 (0.000)
Hypothesis E			0.2 (0.694)	0.7 (0.391)
Hypothesis F			0.0 (0.845)	0.1 (0.729)
Hypothesis G			0.4 (0.669)	3.4 (0.040)
Hypothesis J	4.0 (0.049)	1.8 (0.189)	4.0 (0.050)	1.9 (0.178)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H10: Panel D: Second-stage: onzn to nysi: Hypothesis test results

	(VII) OLS se	(VII) NW se	(VIII) OLS se	(VIII) NW se
Hypothesis A	0.7 (0.394)	1.2 (0.274)	1.2 (0.283)	2.0 (0.161)
Hypothesis B	0.0 (0.841)	0.1 (0.794)	0.3 (0.618)	0.5 (0.478)
Hypothesis C	15.1 (0.000)	25.5 (0.000)	6.4 (0.015)	13.0 (0.001)
Hypothesis D	7.6 (0.001)	16.3 (0.000)	3.3 (0.046)	6.5 (0.003)
Hypothesis E			2.5 (0.123)	4.2 (0.046)
Hypothesis F			0.2 (0.652)	0.4 (0.539)
Hypothesis G			1.4 (0.269)	2.3 (0.114)
Hypothesis J	0.3 (0.616)	0.1 (0.761)	0.1 (0.770)	0.0 (0.858)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table V-H11: Panel A: Second-stage: SUR estimates for configuration (I)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.687 (0.309)**	-1.128 (0.653)*	0.504 (0.255)**	0.683 (0.200)***
Inverse Mills ratio	1050.781 (388.754)***	1550.641 (397.516)****	123.294 (196.063)	307.479 (625.297)
Constant	-848.154 (366.389)**	-353.316 (184.475)*	90.809 (220.183)	-96.961 (1148.003)
R-square	0.352		AIC	4835.363
Chi2-stat.	39.767 (0.000)		BIC	4862.683
n	72		Root MSE	1224.224

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H11: Panel B: Second-stage: SUR estimates for configuration (II)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	-0.038 (0.341)	-0.594 (0.742)	0.731 (0.359)**	0.726 (0.248)***
Inverse Mills ratio	1269.225 (364.942)****	1157.848 (329.222)****	75.139 (201.378)	356.932 (623.477)
1 / t	-5249.879 (2015.510)***	5076.810 (952.831)****	-446.327 (720.717)	-483.791 (1909.541)
MCP / t	10.072 (2.941)****	-9.799 (3.962)**	-16.043 (15.968)	-3.883 (7.560)
Constant	-870.145 (339.981)**	-420.629 (148.870)***	203.435 (245.570)	-59.648 (1154.938)
R-square	0.436		AIC	4835.363
Chi2-stat.	56.592 (0.000)		BIC	4862.683
n	72		Root MSE	1224.224

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H11: Panel C: Second-stage: SUR estimates for configuration (III)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.474 (0.317)	-1.118 (0.703)	-0.028 (0.288)	0.175 (0.194)
Inverse Mills ratio	1819.322 (697.409)***	4230.286 (880.117)****	-764.946 (322.281)**	-2033.390 (1257.689)
HDD PosDev onzn	-1.743 (1.374)	-0.322 (0.890)	-0.435 (0.971)	-1.812 (1.852)
HDD NegDev onzn	6.799 (5.852)	0.365 (3.958)	0.599 (4.182)	-19.446 (9.029)**
CDD PosDev onzn	-23.554 (12.128)*	-4.875 (5.742)	6.361 (8.677)	-17.939 (11.351)
CDD NegDev onzn	-62.066 (21.785)***	0.321 (8.553)	-0.004 (16.235)	-1.941 (18.205)
HDD PosDev external	9.422 (5.455)*	-7.124 (3.803)*	-4.719 (4.052)	3.637 (11.702)
HDD NegDev external	-12.185 (8.080)	3.237 (5.745)	-1.549 (5.851)	-1.212 (12.393)
CDD PosDev external	42.885 (15.530)***	1.493 (7.324)	-18.259 (11.745)	5.012 (14.328)
CDD NegDev external	42.854 (22.051)*	-0.436 (7.748)	15.055 (16.776)	41.689 (16.655)**
Natural gas price	2957.100 (1091.058)***	-870.090 (676.402)	-2133.054 (792.184)***	-3231.139 (1513.690)**
Natural gas capacity ratio	33142.612 (12780.612)***	-6542.623 (7981.321)	-20333.846 (8954.555)**	-33946.353 (17988.987)*
NG price * NG capacity ratio	-6638.300 (2391.484)***	1162.219 (1482.799)	4581.921 (1743.163)***	8432.181 (3398.075)**
Risk-free	-262.488 (134.437)*	-145.086 (96.256)	-184.758 (98.665)*	-172.021 (202.879)
Constant	-16266.764 (6245.956)***	4141.157 (3875.513)	11561.596 (4481.604)***	17555.053 (9643.738)*
R-square	0.598		AIC	4828.462
Chi2-stat.	106.286 (0.000)		BIC	4965.062
n	72		Root MSE	964.296

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H11: Panel D: Second-stage: SUR estimates for configuration (IV)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	-0.274 (0.346)	-0.351 (0.716)	0.183 (0.425)	0.222 (0.263)
Inverse Mills ratio	2085.206 (652.449)***	3476.165 (689.073)****	-749.450 (337.720)**	-2264.176 (1249.449)*
1 / t	-4535.140 (1688.639)***	4964.654 (857.657)****	-1158.731 (799.888)	1896.346 (1750.865)
MCP / t	10.453 (2.794)****	-7.285 (3.945)*	-15.117 (20.230)	-3.389 (8.576)
HDD PosDev onzn	-0.740 (1.315)	0.280 (0.703)	-0.859 (0.989)	-1.892 (1.883)
HDD NegDev onzn	2.007 (5.521)	-0.874 (3.339)	0.704 (4.113)	-21.328 (9.379)**
CDD PosDev onzn	-26.304 (11.207)**	-1.479 (4.459)	7.899 (8.558)	-17.983 (11.304)
CDD NegDev onzn	-62.286 (20.103)***	4.524 (6.634)	2.365 (16.864)	2.279 (18.527)
HDD PosDev external	3.587 (5.283)	-4.216 (3.181)	-4.784 (3.987)	8.351 (11.908)
HDD NegDev external	-5.266 (7.564)	3.878 (4.782)	-1.255 (5.754)	0.711 (12.686)
CDD PosDev external	45.993 (14.349)***	3.385 (5.612)	-21.141 (11.722)*	7.302 (14.198)
CDD NegDev external	50.534 (20.284)**	-0.436 (7.748)	13.301 (16.301)	43.770 (16.565)***
Natural gas price	2055.321 (1036.725)**	-870.090 (676.402)	-2034.309 (783.234)***	-3342.319 (1627.339)**
Natural gas capacity ratio	27144.529 (11914.374)**	-6542.623 (7981.321)	-21454.309 (8819.217)**	-33747.335 (18600.807)*
NG price * NG capacity ratio	-4348.189 (2300.061)*	1162.219 (1482.799)	4280.879 (1724.172)**	8808.344 (3652.953)**
Risk-free	-206.592 (127.154)	-145.086 (96.254)	-220.032 (99.763)**	-153.513 (203.043)
Constant	-14551.863 (5803.802)**	4141.157 (3875.513)	12493.381 (4465.762)***	17342.471 (9930.049)*
R-square	0.655		AIC	4788.296
Chi2-stat.	138.062 (0.000)		BIC	4943.109
n	72		Root MSE	893.091

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H11: Panel E: Second-stage: SUR estimates for configuration (V)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.470 (0.317)	-1.085 (0.520)**	0.487 (0.286)*	0.320 (0.245)
Lag of profit	0.388 (0.108)****	0.112 (0.085)	0.116 (0.164)	0.251 (0.128)*
Inverse Mills ratio	1068.335 (404.222)***	1361.721 (344.404)****	158.915 (211.964)	301.235 (682.235)
Constant	-755.514 (378.807)**	-328.111 (158.649)**	75.873 (236.381)	100.071 (1255.250)
R-square	0.446		AIC	4277.419
Chi2-stat.	54.955 (0.000)		BIC	4311.961
n	64		Root MSE	1186.802

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H11: Panel F: Second-stage: SUR estimates for configuration (VI)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	-0.913 (0.369)**	-0.818 (0.871)	0.717 (0.398)*	0.319 (0.321)
Lag of profit	0.336 (0.090)****	0.119 (0.098)	0.091 (0.163)	0.255 (0.128)**
Inverse Mills ratio	1616.864 (353.210)****	1430.892 (413.759)****	76.921 (235.935)	270.435 (680.990)
1 / t	-30651.741 (6556.039)****	-4694.867 (4147.350)	-1004.099 (1494.745)	-1754.463 (4083.783)
MCP / t	30.995 (5.904)****	8.090 (9.459)	-15.072 (17.068)	-1.644 (9.628)
Constant	-478.308 (319.309)	-263.579 (165.118)	245.153 (306.685)	307.076 (1265.210)
R-square	0.625		AIC	4265.091
Chi2-stat.	108.800 (0.000)		BIC	4316.905
n	64		Root MSE	976.389

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H11: Panel G: Second-stage: SUR estimates for configuration (VII)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	0.556 (0.329)*	-0.696 (0.555)	-0.087 (0.324)	0.055 (0.216)
Lag of profit	0.281 (0.11)**	-0.065 (0.093)	-0.018 (0.154)	0.030 (0.113)
Inverse Mills ratio	2281.350 (776.857)***	4302.941 (783.508)****	-795.013 (363.321)**	-1996.323 (1303.556)
HDD PosDev onzn	-1.470 (1.374)	0.198 (0.687)	-0.642 (1.020)	-1.275 (1.861)
HDD NegDev onzn	2.694 (6.105)	0.670 (3.367)	-1.062 (4.527)	-14.629 (9.235)
CDD PosDev onzn	-27.734 (12.687)**	-6.380 (5.152)	5.210 (9.430)	-16.645 (11.689)
CDD NegDev onzn	-31.573 (25.994)	3.797 (7.835)	1.080 (19.163)	-10.782 (21.054)
HDD PosDev external	16.874 (6.190)***	-3.256 (3.123)	-3.382 (4.785)	2.538 (12.538)
HDD NegDev external	-4.333 (8.681)	3.365 (4.822)	0.613 (6.524)	-6.908 (12.845)
CDD PosDev external	37.512 (16,481)**	8.168 (6.866)	-20.244 (13.215)	4.326 (15.604)
CDD NegDev external	24.661 (24.689)	2.137 (6.927)	13.592 (18.746)	53.314 (18.986)***
Natural gas price	1276.955 (1294.066)	-1031.815 (615.035)*	-2758.581 (903.849)***	-2099.239 (1648.584)
Natural gas capacity ratio	18160.533 (14459.215)	-5724.248 (7001.459)	-2758.581 (903.849)***	-19511.677 (19624.090)
NG price * NG capacity ratio	-3379.292 (2777.738)	1647.003 (1336.395)	-27554.983 (10326.363)***	5988.340 (3689.089)
Risk-free	-235.283 (150.904)	-102.673 (80.811)	-272.431 (113.063)**	-30.915 (221.026)
Constant	-8613.726 (7104.672)	3071.255 (3414.402)	15238.936 (5142.150)***	10128.963 (10535.637)
R-square	0.643		AIC	4276.087
Chi2-stat.	115.019 (0.000)		BIC	4414.256
n	64		Root MSE	952.939

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H11: Panel H: Second-stage: SUR estimates for configuration (VIII)

	MISI to ONZN	NYSI to ONZN	ONZN to MISI	ONZN to NYSI
MCP	-1.422 (0.408)****	-1.769 (1.031)*	0.086 (0.552)	0.179 (0.282)
Lag of profit	0.158 (0.091)*	-0.147 (0.127)	-0.042 (0.150)	0.011 (0.111)
Inverse Mills ratio	2666.121 (622.224)****	4571.473 (824.922)****	-1042.404 (422.438)**	-1866.178 (1271.396)
1 / t	-37215.704 (6522.128)****	-4297.152 (5560.223)	-4135.067 (1891.067)**	8714.557 (4262.486)**
MCP / t	35.755 (5.732)****	12.943 (11.707)	-23.518 (28.462)	-7.285 (9.409)
HDD PosDev onzn	-1.105 (1.123)	0.376 (0.700)	-1.543 (1.046)	-0.908 (1.847)
HDD NegDev onzn	1.609 (4.948)	-0.584 (3.512)	0.361 (4.423)	-23.928 (10.048)**
CDD PosDev onzn	-30.876 (10.054)***	-8.155 (5.412)	8.807 (9.254)	-17.647 (11.351)
CDD NegDev onzn	-69.165 (21.539)***	2.848 (7.862)	10.880 (24.199)	-1.172 (22.587)
HDD PosDev external	0.124 (5.626)	-5.753 (3.928)	-3.133 (4.602)	1.046 (12.124)
HDD NegDev external	-1.261 (6.955)	5.213 (5.058)	-0.627 (6.364)	7.113 (14.027)
CDD PosDev external	45.641 (13.191)****	11.411 (7.280)	-26.286 (13.144)**	4.815 (15.085)
CDD NegDev external	58.641 (20.308)***	3.495 (6.946)	7.347 (19.747)	55.074 (18.869)***
Natural gas price	2328.116 (1066.415)**	-1013.225 (718.646)	-2074.636 (935.765)**	-3436.927 (1807.927)*
Natural gas capacity ratio	24633.922 (11580.395)**	-6043.115 (7325.956)	-23226.496 (10148.765)**	-30386.489 (20167.884)
NG price * NG capacity ratio	-5241.366 (2316.022)**	1654.842 (1592.047)	4238.618 (2082.390)**	9269.539 (4092.016)**
Risk-free	-264.130	-130.502	-343.596	-49.099

	(120.988)**	(3455.348)	(113.326)***	(214.477)
Constant	-11923.401 (5657.575)**	3217.872 (3455.348)	14572.119 (5040.129)	13784.318 (10548.070)
R-square	0.776		AIC	4251.372
Chi2-stat.	225.463 (0.000)		BIC	4406.811
n	64		Root MSE	753.957

Note: SUR standard errors are in parentheses.

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table V-H12: SUR: misi to onzn: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	5.4 (0.021)	6.6 (0.010)	6.8 (0.009)	6.3 (0.012)
Hypothesis B	4.9 (0.026)	0.0 (0.911)	2.2 (0.134)	0.6 (0.428)
Hypothesis C	1.0 (0.310)	9.3 (0.002)	2.8 (0.097)	13.6 (0.000)
Hypothesis D	5.4 (0.066)	12.6 (0.002)	7.6 (0.023)	16.7 (0.000)
Hypothesis E		6.8 (0.009)		7.2 (0.007)
Hypothesis F		11.7 (0.001)		14.0 (0.000)
Hypothesis G		12.2 (0.002)		14.2 (0.001)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H12: SUR: misi to onzn: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	4.0 (0.046)	2.2 (0.135)	1.5 (0.225)	4.4 (0.035)
Hypothesis B	2.2 (0.138)	6.1 (0.013)	2.9 (0.091)	12.2 (0.000)
Hypothesis C	2.8 (0.095)	26.9 (0.000)	1.8 (0.177)	35.3 (0.000)
Hypothesis D	5.3 (0.072)	27.9 (0.000)	2.6 (0.279)	35.7 (0.000)
Hypothesis E		21.9 (0.000)		32.6 (0.000)
Hypothesis F		27.6 (0.000)		38.9 (0.000)
Hypothesis G		30.2 (0.000)		39.7 (0.000)
Hypothesis J	12.9 (0.000)	14.0 (0.000)	6.4 (0.011)	3.0 (0.083)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H13: SUR: nysi to onzn: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	3.7 (0.055)	8.0 (0.005)	1.1 (0.285)	0.4 (0.533)
Hypothesis B	3.0 (0.084)	0.6 (0.423)	2.5 (0.112)	0.2 (0.624)
Hypothesis C	10.6 (0.001)	4.6 (0.032)	9.1 (0.003)	3.6 (0.059)
Hypothesis D	14.8 (0.001)	13.6 (0.001)	11.8 (0.003)	4.0 (0.136)
Hypothesis E		28.4 (0.000)		33.5 (0.000)
Hypothesis F		6.1 (0.013)		3.4 (0.065)
Hypothesis G		37.9 (0.000)		47.7 (0.000)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H13: SUR: nysi to onzn: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	4.3 (0.039)	2.5 (0.110)	0.8 (0.368)	0.9 (0.352)
Hypothesis B	4.4 (0.037)	0.9 (0.347)	1.6 (0.210)	2.9 (0.086)
Hypothesis C	16.1 (0.000)	4.4 (0.037)	9.3 (0.002)	7.2 (0.007)
Hypothesis D	20.8 (0.000)	7.3 (0.026)	12.0 (0.000)	9.4 (0.009)
Hypothesis E		1.3 (0.258)		0.6 (0.440)
Hypothesis F		0.7 (0.392)		1.2 (0.269)
Hypothesis G		1.8 (0.412)		1.9 (0.392)
Hypothesis J	1.7 (0.187)	1.5 (0.226)	0.5 (0.488)	1.4 (0.245)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H14: SUR: onzn to misi: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	0.2 (0.680)	0.7 (0.407)	6.7 (0.010)	7.8 (0.005)
Hypothesis B	3.9 (0.048)	4.1 (0.042)	0.0 (0.922)	0.2 (0.667)
Hypothesis C	3.8 (0.051)	0.6 (0.454)	12.7 (0.000)	3.7 (0.054)
Hypothesis D	4.1 (0.131)	1.4 (0.509)	16.0 (0.000)	9.8 (0.007)
Hypothesis E		0.4 (0.536)		2.1 (0.147)
Hypothesis F		1.0 (0.315)		0.6 (0.455)
Hypothesis G		1.6 (0.456)		2.7 (0.265)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H14: SUR: onzn to misi: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	0.1 (0.748)	0.6 (0.424)	8.8 (0.003)	8.4 (0.004)
Hypothesis B	2.9 (0.088)	3.3 (0.071)	0.1 (0.789)	0.0 (0.876)
Hypothesis C	3.2 (0.073)	0.5 (0.477)	11.3 (0.001)	2.7 (0.098)
Hypothesis D	3.4 (0.185)	1.2 (0.560)	17.3 (0.000)	9.3 (0.010)
Hypothesis E		0.5 (0.502)		4.8 (0.029)
Hypothesis F		0.8 (0.377)		0.7 (0.409)
Hypothesis G		1.5 (0.469)		5.7 (0.058)
Hypothesis J	0.5 (0.478)	0.3 (0.576)	0.0 (0.906)	0.1 (0.777)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H15: SUR: onzn to nysi: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	0.0 (0.933)	0.0 (0.959)	3.3 (0.069)	3.1 (0.081)
Hypothesis B	11.6 (0.001)	8.6 (0.003)	0.8 (0.368)	0.7 (0.400)
Hypothesis C	2.5 (0.114)	1.2 (0.270)	18.1 (0.000)	8.7 (0.003)
Hypothesis D	2.6 (0.276)	1.3 (0.532)	18.2 (0.000)	9.1 (0.011)
Hypothesis E		0.1 (0.800)		1.2 (0.279)
Hypothesis F		0.3 (0.608)		0.2 (0.693)
Hypothesis G		0.9 (0.644)		1.2 (0.549)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H15: SUR: onzn to nysi: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	0.0 (0.936)	0.1 (0.808)	0.9 (0.336)	1.7 (0.191)
Hypothesis B	1.7 (0.191)	1.0 (0.320)	0.1 (0.801)	0.4 (0.524)
Hypothesis C	7.7 (0.005)	4.5 (0.033)	19.1 (0.000)	8.5 (0.004)
Hypothesis D	7.8 (0.020)	4.5 (0.103)	19.1 (0.000)	8.7 (0.013)
Hypothesis E		0.2 (0.667)		4.2 (0.041)
Hypothesis F		0.0 (0.864)		0.6 (0.439)
Hypothesis G		0.8 (0.657)		4.3 (0.114)
Hypothesis J	3.8 (0.051)	4.0 (0.046)	0.1 (0.791)	0.0 (0.917)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H16: SUR: All paths jointly: Hypothesis test results: Panel A

	(I)	(II)	(III)	(IV)
Hypothesis A	7.7 (0.104)	11.7 (0.020)	18.8 (0.001)	17.9 (0.001)
Hypothesis B	23.8 (0.000)	12.8 (0.013)	6.0 (0.200)	1.7 (0.796)
Hypothesis C	16.9 (0.002)	13.6 (0.009)	41.3 (0.000)	28.2 (0.000)
Hypothesis D	24.2 (0.002)	24.0 (0.002)	53.3 (0.000)	38.4 (0.000)
Hypothesis E		49.7 (0.000)		50.6 (0.000)
Hypothesis F		26.2 (0.000)		20.6 (0.000)
Hypothesis G		64.2 (0.000)		70.1 (0.000)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H16: SUR: All paths jointly: Hypothesis test results: Panel B

	(V)	(VI)	(VII)	(VIII)
Hypothesis A	6.6 (0.158)	4.5 (0.342)	11.8 (0.019)	14.0 (0.007)
Hypothesis B	12.3 (0.015)	10.5 (0.032)	4.9 (0.294)	14.9 (0.005)
Hypothesis C	27.6 (0.000)	33.2 (0.000)	39.9 (0.000)	52.2 (0.000)
Hypothesis D	33.6 (0.000)	37.6 (0.000)	49.6 (0.000)	61.1 (0.000)
Hypothesis E		22.5 (0.000)		41.7 (0.000)
Hypothesis F		28.5 (0.000)		40.2 (0.000)
Hypothesis G		34.1 (0.000)		50.9 (0.000)
Hypothesis J	18.4 (0.001)	19.1 (0.001)	7.0 (0.134)	4.5 (0.343)

Note: This table reports chi2-statistics, with associated p-values in parentheses.

Table V-H17: SUR: Panel A: misi to onzn: 90% confidence intervals for MCP

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	0.170	0.694	1.218	-0.033	0.694	1.421	0.179	0.687	1.194
(II)	-0.565	0.039	0.643	-0.668	0.039	0.745	-0.599	-0.038	0.523
(III)	-0.105	0.478	1.061	-0.292	0.478	1.249	-0.047	0.474	0.995
(IV)	-0.795	-0.147	0.501	-0.878	-0.147	0.584	-0.843	-0.274	0.295
(V)	0.054	0.597	1.139	-0.125	0.597	1.319	-0.052	0.470	0.992
(VI)	-1.442	-0.801	-0.161	-1.648	-0.801	0.045	-1.519	-0.913	-0.307
(VII)	-0.085	0.540	1.164	-0.244	0.540	1.323	0.015	0.556	1.097
(VIII)	-2.062	-1.275	-0.488	-2.266	-1.275	-0.285	-2.093	-1.422	-0.751

Table V-H17: SUR: Panel B: nysi to onzn: 90% confidence intervals for MCP

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	-1.973	-1.007	-0.040	-1.973	-1.007	-0.040	-2.202	-1.128	-0.053
(II)	-1.754	-0.726	0.302	-1.927	-0.726	0.475	-1.815	-0.594	0.627
(III)	-1.600	-0.441	0.718	-1.310	-0.441	0.427	-2.274	-1.118	0.038
(IV)	-1.213	-0.043	1.127	-0.854	-0.043	0.768	-1.529	-0.351	0.827
(V)	-1.832	-0.975	-0.119	-2.026	-0.975	0.076	-1.941	-1.085	-0.230
(VI)	-2.281	-0.895	0.491	-2.366	-0.895	0.575	-2.251	-0.818	0.614
(VII)	-1.496	-0.482	0.533	-1.209	-0.482	0.245	-1.609	-0.696	0.216
(VIII)	-2.881	-1.017	0.846	-2.862	-1.017	0.827	-3.464	-1.769	-0.073

Table V-H17: SUR: Panel C: onzn to misi: 90% confidence intervals for MCP

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	0.311	0.476	0.641	0.383	0.476	0.568	0.085	0.504	0.923
(II)	0.243	0.739	1.235	0.524	0.739	0.954	0.140	0.731	1.322
(III)	0.265	0.458	0.650	0.310	0.458	0.605	-0.503	-0.028	0.446
(IV)	-0.010	0.638	1.286	0.359	0.638	0.917	-0.516	0.183	0.881
(V)	0.208	0.452	0.696	0.296	0.452	0.607	0.017	0.487	0.958
(VI)	0.129	0.677	1.225	0.460	0.677	0.894	0.063	0.717	1.371
(VII)	0.003	0.294	0.585	0.064	0.294	0.524	-0.619	-0.087	0.446
(VIII)	-0.123	0.699	1.522	0.264	0.699	1.134	-0.821	0.086	0.994

Table V-H17: SUR: Panel D: onzn to nysi: 90% confidence intervals for MCP

Model	OLS Lower	OLS Point	OLS Upper	NW Lower	NW Point	NW Upper	SUR Lower	SUR Point	SUR Upper
(I)	0.304	0.643	0.983	0.407	0.643	0.879	0.353	0.683	1.013
(II)	0.281	0.703	1.136	0.456	0.703	0.960	0.318	0.726	1.135
(III)	-0.201	0.158	0.516	-0.217	0.158	0.532	-0.145	0.175	0.494
(IV)	-0.275	0.224	0.724	-0.198	0.224	0.646	-0.211	0.222	0.655
(V)	-0.105	0.306	0.717	0.100	0.306	0.512	-0.083	0.320	0.722
(VI)	-0.242	0.307	0.856	0.017	0.307	0.597	-0.209	0.319	0.846
(VII)	-0.360	0.049	0.459	-0.266	0.049	0.365	-0.301	0.055	0.410
(VIII)	-0.387	0.165	0.718	-0.223	0.165	0.553	-0.284	0.179	0.643

Appendix VI-A: LT FTR data and statistics

Table VI-A1: LT FTR: MCP and payout summary statistics ignoring path distinction

Variable	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
Payout	395	6,732.34	12,129.24	2.60	10.53	0.00	72,793.44
MCP	395	3,359.05	6,171.80	3.26	15.60	13.75	42,779.70

Table VI-A2: LT FTR: MCP and payout summary statistics for import paths

Source	Variable	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
MBSI	Payout	26	9,075.92	8,247.70	2.57	11.13	1234.25	42,192.07
MBSI	MCP	26	4,243.84	2,914.64	1.41	4.38	1125.00	12,312.94
MISI	Payout	25	12,351.10	11,777.27	0.46	1.73	0.10	32,917.78
MISI	MCP	25	8,457.52	7,264.92	0.78	2.88	241.00	27,471.20
MNSI	Payout	24	25,272.68	22,239.67	0.81	2.39	1800.71	72,793.44
MNSI	MCP	24	13,095.26	11,386.01	1.01	2.63	712.50	36,539.38
NYSI	Payout	25	4,590.95	9,112.80	3.79	17.57	0.00	45,448.33
NYSI	MCP	25	2,822.74	2,621.46	1.07	3.34	173.35	8,862.00
PQBE	Payout	31	1,993.34	3,090.01	1.33	3.10	37.07	8,661.54
PQBE	MCP	31	532.41	739.99	2.84	11.72	59.57	3,656.83
PQDA	Payout	31	37.51	94.77	3.55	15.93	0.00	473.57
PQDA	MCP	31	261.56	406.52	3.35	13.22	48.75	1,942.74
PQDZ	Payout	29	761.59	3,499.72	5.10	26.99	0.10	18,950.84
PQDZ	MCP	29	422.47	503.68	2.43	8.06	36.25	2,173.39
PQPC	Payout	31	1,479.16	3,603.91	2.20	5.86	0.00	10,710.01
PQPC	MCP	31	31.96	359.61	1.47	3.65	13.75	1,225.00
PQXY	Payout	30	116.78	264.21	2.10	5.51	0.00	775.99
PQXY	MCP	30	222.26	182.48	1.31	4.34	25.50	725.00

Table VI-A3: LT FTR: MCP and payout summary statistics for export paths

Sink	Variable	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
MBSI	Payout	21	326.21	560.68	2.27	7.22	0.00	2,180.83
MBSI	MCP	21	811.50	997.63	1.04	2.80	20.25	3,290.32
MISI	Payout	23	5,554.36	9,279.06	1.62	4.06	0.00	28,577.55
MISI	MCP	23	1,316.91	2,247.22	2.71	9.74	59.00	9,614.10
MNSI	Payout	23	11,163.04	11,630.49	0.80	2.31	0.00	35,220.91
MNSI	MCP	23	2,739.69	2,627.50	1.54	5.19	141.00	10,920.73
NYSI	Payout	23	15,284.81	15,331.23	1.83	5.65	787.07	58,019.82
NYSI	MCP	23	7,221.84	6,044.25	2.24	9.55	318.75	29,762.10
PQDA	Payout	23	63.58	130.96	1.71	3.94	0.00	342.21
PQDA	MCP	23	288.94	227.54	1.78	6.12	48.75	1,024.35
PQHZ	Payout	30	17,148.89	15,092.92	0.95	3.27	20.00	56,047.64
PQHZ	MCP	30	9,461.18	10,192.42	1.63	5.59	81.00	42,770.70

Table VI-A4: LT FTR: Summary statistics for ex-post profits

Path	N	Mean	Std. Dev.	Skewness	Kurtosis	Minimum	Maximum
All paths	395	3,373.29	10,803.44	2.01	12.10	-40,446.43	66,426.91
MBSI to ONZN	26	4,832.08	7,889.77	1.43	7.03	-8,703.19	32,515.89
MISI to ONZN	25	3,893.57	12,839.71	-0.21	2.91	-25,891.00	29,413.40
MNSI to ONZN	24	12,177.42	26,826.93	0.43	2.50	-29,447.22	66,426.91
NYSI to ONZN	25	1,768.20	8,894.96	3.33	15.13	-7,604.55	40,131.33
PQBE to ONZN	31	1,460.92	3,181.31	1.07	2.76	-2,941.73	7,960.04
PQDA to ONZN	31	-224.05	336.32	-3.02	11.29	-1,469.17	107.03
PQDZ to ONZN	29	339.12	3,253.34	4.96	26.14	-1,964.26	17,111.33
PQPC to ONZN	31	1,165.20	3,679.89	2.18	5.82	-1,204.96	10,634.76
PQXY to ONZN	30	-105.49	355.16	1.07	3.97	-725.00	747.79
ONZN to MBSI	21	-485.28	1,201.28	-0.68	2.44	-3,116.70	1,234.76
ONZN to MISI	23	4,237.44	8,016.36	1.88	5.13	-1,287.44	26,427.05
ONZN to MNSI	23	8,423.34	11,462.55	0.87	2.42	-3,152.42	31,319.16
ONZN to NYSI	23	8,062.97	14,807.92	1.63	5.24	-11,368.48	48,818.48
ONZN to PQDA	23	-226.36	268.42	-1.17	4.37	-999.57	126.71
ONZN to PQHZ	30	7,687.71	14,724.67	-0.80	5.50	-40,446.43	40,586.24

Table VI-A5: LT FTR: Correlation between MCP and payout and its statistical significance¹⁶⁰

Path	Corr. Coefficient	p-value ¹⁶¹
All paths considered	0.4575	0.0000
MBSI to ONZN	0.2969	0.1409
MISI to ONZN	0.1556	0.4577
MNSI to ONZN	-0.1885	0.3778
NYSI to ONZN	0.2259	0.2775
PQBE to ONZN	-0.0055	0.9768
PQDA to ONZN	0.7934	0.0000
PQDZ to ONZN	0.5439	0.0023
PQPC to ONZN	-0.1551	0.4046
PQXY to ONZN	-0.2388	0.2038
ONZN to MBSI	-0.1193	0.6065
ONZN to MISI	0.6448	0.0009
ONZN to MNSI	0.1764	0.4207
ONZN to NYSI	0.2822	0.1920
ONZN to PQDA	-0.0524	0.8122
ONZN to PQHZ	0.3733	0.0421

Table VI-A6: LT FTR: Summary statistics for various additional variables

Variable	N	Mean	Std. Dev.	Minimum	Maximum
1 / t	31	0.13	0.19	0.03	1.00
Natural Gas Price	31	6.80	1.42	4.17	9.09
Natural Gas Capacity Ratio	31	0.44	0.07	0.35	0.60
Risk-free Interest Rate	31	2.39	1.27	0.16	4.13

¹⁶⁰ As noted in the text, the correlation coefficients and p-values reported in this table ignore the issue of serial dependence resulting from overlapping FTR rights periods.

¹⁶¹ The p-value relates the test of statistical significance of the correlation coefficient, where the null and alternative hypotheses are that the correlation is zero and otherwise, respectively. The overlapping nature of the data is ignored.

Figure VI-A1: LT FTR: Scatter plot of MCP against payout for all paths¹⁶²

¹⁶² "All paths" excludes, as described in the text, both path directions on the Quebec AT transmission line.

Figure VI-A2: LT FTR: Scatter plots of MCP against payout for import paths

Panel A: Non-Quebec import paths

Panel B: Quebec import paths

Figure IV-A7: LT FTR: Scatter plots of MCP against payout for export paths

Figure IV-A8: LT FTR: Time series plots of MCP and payout for import paths

Panel A: Non-Quebec import paths

Panel B: Quebec import paths

Figure IV-A9: LT FTR: Time series plots of MCP and payout for export paths

Appendix VI-B: Estimation results with LT FTR data

Table VI-B1: OLS on pooled cross-section with overlapping data: Estimates and diagnostic tests

	Model (I)	Model (III)
MCP	0.764 (0.179)****	0.809 (0.156)****
Natural gas price		3787.249 (867.684)****
Risk-free rate		-3822.355 (792.896)****
Constant	5826.258 (801.600)****	-11102.160 (4422.269)**
R-square	0.155	0.244
Adj. R-square	0.152	0.236
AIC	6118.336	6090.811
BIC	6125.620	6105.379
Root MSE	12402.351	11770.257
Overall F-stat	51.278 (0.000)	29.938 (0.000)
N	282	282
Condition No.	1.86	16.44
Mean VIF	1.00	1.44
BP, standard	0.000	0.000
BP, N*R2	0.000	0.000
BP, F-stat	0.000	0.000
White's test	0.00	0.00
Skew-kurt test	0.000	0.000
Linktest	-7.30	0.18
RESET test	0.000	0.002

Note: Huber-White standard errors reported in parentheses. Structural break dummy variable estimates omitted from the table. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (number) and Mean VIF, the reported values are un-normalised test statistics.

Table VI-B2: OLS on pooled cross-section with overlapping data: Hypothesis test results

	Model (I)	Model (III)
Hypothesis A	52.8 (0.000)	6.3 (0.013)
Hypothesis B	18.2 (0.000)	27.1 (0.000)
Hypothesis C	1.7 (0.188)	1.5 (0.221)
Hypothesis D	33.0 (0.000)	4.6 (0.011)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table VI-B3: Fixed path-specific effects with overlapping data: Estimates and diagnostic tests

	Model (I)	Model (III)
MCP	0.249 (0.254)	0.309 (0.195)
Natural gas price		3611.091 (1650.897)*
Risk-free rate		-3581.350 (1503.350)
Constant	8188.351 (1164.327)****	-8192.189 (8220.676)
corr(u_i, Xb)	0.559	0.279
s.e. u_i	6712.069	6511.156
s.e. e_{it}	11415.805	10774.333
Rho	0.257	0.268
All u_i=0 F-test	6.049 (0.000)	6.377 (0.000)
Overall R²	0.155	0.194
Log Likelihood	-3028.666	-3011.309
Overall F-test	4.160 (0.000)	13.259 (0.000)
N	282	282
Wald HC test	0.000	0.000
Woold. AC test	0.000	0.000
BP CD test	0.000	0.000
Pesaran test	0.777	0.939

Note: Huber-White robust panel standard errors are reported in parentheses.

Coefficient estimates are common among the three cases. 'corr(u_i, Xb)' refers to the correlation between u_i and the regressors listed. 'Rho' refers to the fraction of variation that is due to u_i. HC, AC, and CD denote heteroskedasticity, autocorrelation, and cross-sectional dependence, respectively (reported figures are p-values).

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table VI-B4: Fixed path-specific effects with overlapping data: Hypothesis test results

	Model (I)	Model (III)
Hypothesis A	49.5 (0.000)	1.0 (0.342)
Hypothesis B	1.0 (0.350)	2.5 (0.144)
Hypothesis C	8.7 (0.014)	12.6 (0.005)
Hypothesis D	49.5 (0.000)	6.6 (0.015)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table VI-B5: Random path-specific effects with overlapping data: Estimates and diagnostic tests

	Model (I)	Model (III)
MCP	0.705 (0.151)****	0.651 (0.119)****
Natural gas price		3726.706 (1655.313)**
Risk-free rate		-3748.035 (1663.277)**
Constant	6119.621 (2059.691)***	-10090.366 (6524.523)
s.e. u_i	997.863	1789.971
s.e. e_it	11415.805	10774.333
Rho	0.008	0.027
BP RE test	0.000	0.000
Pesaran test	0.535	0.380
Overall R2	0.155	0.241
Over. chi2-test	42.022 (0.000)	65.853 (0.000)
N	282	282

Note: Huber-White robust panel standard errors are reported in parentheses. 'Rho' refers to the fraction of variation that is due to u_i .

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table VI-B6: Random path-specific effects with overlapping data: Hypothesis test results

	Model (I)	Model (III)
Hypothesis A	8.8 (0.003)	2.4 (0.122)
Hypothesis B	21.8 (0.000)	30.0 (0.000)
Hypothesis C	3.8 (0.051)	8.6 (0.003)
Hypothesis D	11.2 (0.004)	8.8 (0.012)

Note: This table reports chi-square statistics, with associated p-values in parentheses.

Table VI-B7: Hausman test: Comparison of fixed- and random-effects models with overlapping data

	Model (I)	Model (III)
Hausman test p-value	0.000	0.000

Table VI-B8: OLS on pooled cross-section with non-overlapping data: Estimates and diagnostic tests

	Model (I)	Model (III)
MCP	0.845 (0.348)**	0.847 (0.296)***
Natural gas price		3490.418 (1886.870)*
Risk-free rate		-3091.897 (1634.274)*
Constant	5815.967 (1590.210)****	-10348.856 (9123.022)
R-square	0.157	0.202
Adj. R-square	0.147	0.170
AIC	1732.435	1732.139
BIC	1737.199	1741.667
Root MSE	12045.416	11879.574
Overall F-stat	14.577 (0.000)	6.393 (0.001)
N	80	80
Condition No.	1.88	20.84
Mean VIF	1.00	1.94
BP, standard	0.001	0.008
BP, N*R2	0.076	0.153
BP, F-stat	0.077	0.157
White's test	0.20	0.78
Skew-kurt test	0.000	0.000
Linktest	-2.28	-0.27
RESET test	0.029	0.153

Note: Huber-White standard errors reported in parentheses. Structural break dummy variable estimates omitted from the table. Reported results for BP, White's, skewness-kurtosis, and RESET tests are p-values. For Linktest, the reported value is the t-statistic associated with the squared term. For Condition No. (number) and Mean VIF, the reported values are un-normalised test statistics.

Table VI-B9: OLS on pooled cross-section with non-overlapping data: Hypothesis test results

	Model (I)	Model (III)
Hypothesis A	13.4 (0.000)	1.3 (0.260)
Hypothesis B	5.9 (0.018)	8.2 (0.005)
Hypothesis C	0.2 (0.657)	0.3 (0.606)
Hypothesis D	9.2 (0.000)	0.7 (0.483)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table VI-B10: Fixed path-specific effects with non-overlapping data: Estimates and diagnostic tests

	Model (I)	Model (III)
MCP	0.322 (0.479)	0.325 (0.426)
Natural gas price		3399.127 (2456.317)
Risk-free rate		-2898.828 (2110.321)
Constant	7955.164 (1959.480)***	-8074.033 (11085.680)
corr(u_i, Xb)	0.521	0.325
s.e. u_i	6361.098	6302.889
s.e. e_it	11600.311	11415.070
Rho	0.231	0.234
All u_i=0 F-test	1.610 (0.122)	1.631 (0.117)
Overall R2	0.157	0.165
Log Likelihood	-855.717	-853.235
Overall F-test	1.544 (0.136)	1.940
N	80	80
Wald HC test	0.000	0.000
Woold. AC test	0.205	0.059
PesaranCD test	0.490	0.812

Note: Huber-White robust panel standard errors are reported in parentheses.

Coefficient estimates are common among the three cases. 'corr(u_i, Xb)' refers to the correlation between u_i and the regressors listed. 'Rho' refers to the fraction of variation that is due to u_i. HC, AC, and CD denote heteroskedasticity, autocorrelation, and cross-sectional dependence, respectively (reported figures are p-values).

* p<0.1, ** p<0.05, *** p<0.01, **** p<0.001

Table VI-B11: Fixed path-specific effects with non-overlapping data:: Hypothesis test results

	Model (I)	Model (III)
Hypothesis A	16.5 (0.002)	0.5 (0.483)
Hypothesis B	0.5 (0.516)	0.6 (0.463)
Hypothesis C	2.0 (0.187)	2.5 (0.144)
Hypothesis D	16.5 (0.002)	1.3 (0.325)

Note: This table reports F-statistics, with associated p-values in parentheses.

Table VI-B12: Random path-specific effects with non-overlapping data: Estimates and diagnostic tests

	Model (I)	Model (III)
MCP	0.845 (0.277)***	0.847 (0.240)****
Natural gas price		3490.418 (2641.991)
Risk-free rate		-3091.897 (2556.493)
Constant	5815.967 (2364.061)**	-10348.856 (10229.162)
s.e. u_i	0.000	0.000
s.e. e_it	11600.311	11415.070
Rho	0.000	0.000
BP RE test	0.618	0.388
Pesaran test	0.895	0.867
Overall R2	0.157	0.202
Over. chi2-test	14.577 (0.000)	19.180 (0.000)
N	80	80

Note: Huber-White robust panel standard errors are reported in parentheses. 'Rho' refers to the fraction of variation that is due to u_i .

* $p < 0.1$, ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Table VI-B13: Random path-specific effects with overlapping data: Hypothesis test results

	Model (I)	Model (III)
Hypothesis A	6.1 (0.014)	1.0 (0.312)
Hypothesis B	9.3 (0.002)	12.5 (0.000)
Hypothesis C	0.3 (0.575)	0.4 (0.523)
Hypothesis D	19.7 (0.000)	1.1 (0.589)

Note: This table reports chi-square statistics, with associated p-values in parentheses.

Table VI-B14: Hausman test: Comparison of fixed- and random-effects models with non-overlapping data

	Model (I)	Model (III)
Hausman test p-value	0.000	0.002