Supplement to the paper
"California's cap-and-trade program and emission leakage in the Western Interconnection: comparing econometric and partial equilibrium model estimates"

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Section A of this supplement presents JHSMINE formulation. Section B shows the frequency histograms of 2009-10 capacity factors by technology, region and block of hour (Figure A1), capacity factor trajectories of matched treated and control plants by region (Figure A2), treatment heterogeneity by hour of day based on one of our robustness checks (Figure A3), and OLS and robust confidence intervals for the post period treatment effects under varying restrictions and values of M (Figures A4-A5). Lastly, Section C includes summary statistics for nuclear, hydro and renewable generation in the treated and control regions (Table A1), balancing tests (Tables A2-A3), the assumed state-level RPS requirements (Table A4) and the shares of electricity imports used in JHSMINE (Table A5).

A. JHSMINE formulation

A market model consists of submodels for individual market participants and a set of market clearing conditions linking participant decisions (e.g., supply = demand for electricity and other commodities). Equilibrium models search for a set of solutions that satisfy a) each submodel's first order conditions, subject to participant expectations about how the rest of the market will react if it changes its decisions, and b) market clearing conditions. Under some conditions, it is possible to define a single-objective problem yielding a solution equivalent to the equilibrium for competitive and oligopolistic models. For example, under the assumption of perfectly inelastic demand a competitive equilibrium among power producers is equivalent to minimization of total generation costs. In this section we present the optimization problems of the market players in JHSMINE (the system operator, generation companies and load serving entities) and the market clearing conditions. Under the assumptions of perfectly inelastic demand and perfect competition, the market equilibrium is obtained by solving an equivalent single optimization problem, whose objective is to minimize the sum of individual objectives. The constraints of this single optimization are formed by the union of constraints of each individual player and the market clearing conditions. The model has hourly resolution and is solved for eight representative days in 2013 and 2016. The nomenclature of JHSMINE is presented at the end of the formulation.

I. System Operator

The system operator (SO) arbitrages any differences in nodal prices on the network by buying power at one location and selling it to the other. This can be viewed as spatial arbitrage. The SO's objective is to maximize the annual profit from spatial arbitrage across the nodes of the network:[1]

$$\sum_h HW_h \cdot \sum_l \left(\lambda^{LMP}_{h,i_l^{To}} - \lambda^{LMP}_{h,i_l^{From}}\right) \cdot pf_{h,l} \tag{1}$$

where HW_h is the number of hours represented by hour h, $\lambda^{LMP}_{h,i}$ is the locational marginal price at hour h and node i, and $\left(\lambda^{LMP}_{h,i_l^{To}} - \lambda^{LMP}_{h,i_l^{From}}\right)$ is the price difference between the receiving node and the sending node of transmission line l. Constraint (2) is the DC power flow at hour h through transmission line l:[2]

$$pf_{h,l} = B_l \cdot BP \cdot \left(\theta_{h,i_l^{From}} - \theta_{h,i_l^{To}}\right) \quad \forall h, l \notin L^{DC} \tag{2}$$

Based on equations (3) and (4), power flows cannot exceed transmission capacity limits.

$$pf_{h,l} \leq LTM_l \quad \forall h, l \tag{3}$$

$$-pf_{h,l} \leq LTM_l \quad \forall h, l \tag{4}$$

II. Generation Companies

Each generation company (GenCO) k in JHSMINE owns and operates one power plant.[3] The GenCO sells energy, as well as the non-electrical attributes associated with its power generation (emissions and renewable energy credits), whose demand is created through regulation. Energy (denoted by *gopt* in the model) is sold to the system operator at the nodal electricity price, λ^{LMP}. The non-electrical attributes of power are traded instead through bilateral contracts, and remunerated separately from the energy output.

[1] System operators are non-profit entities that operate but do not own network or generation assets. Although maximization of profits from spatial arbitrage is not the objective of real-world system operators, the SO problem formulation in JHSMINE is equivalent to one in which the SO adjusts demand and arbitrage variables to maximize consumer benefit from power consumption, subject to fixed values of generator sales and output (Hobbs and Helman, 2004).

[2] Note that the DC approximation applies to AC transmission lines. Power flows radially on HVDC lines in the model (e.g., the Intermountain HVDC between Utah and California and the Pacific DC Intertie).

[3] The formulation may be generalized to allow for GenCOs that own and operate multiple generators.

In particular, the GenCO may enter bilateral contracts with load serving entities in its own state, neighbor states or states adjacent to their neighbors: the variable $cpfs^S$ refers to the emission attribute associated with a contract for specified source power (in MW) sold by generator k at a price λ^{SEC}. Further, if GenCO k is outside of California, it may also enter contracts to sell unspecified source power to a pool. Thus, the variable $cpfs^U$ refers to the emissions associated with a contract for unspecified source power (in MW) sold by out-of-state generator k at a price λ^{UEC}; the emission rate of unspecified power is 0.428 ton/MWh. In addition, any GenCO in WECC may enter bilateral contracts with load serving entities in its own state, neighbor states or states adjacent to their neighbors to sell its renewable energy credits (denoted by $recs$ in the model).

We present the problem of in-state electricity producers and producers in the rest of WECC separately, because the former can only sell specified power and are subject to the cap-and-trade program.

The objective of GenCOs in California ($k \in K_{CA}$) is to maximize the annual profit equal to the revenues from the electricity market, specified power contracts and renewable energy contracts, minus the variable costs of generation and the cost of emission allowances:

$$\begin{aligned}\sum_h HW_h \cdot \Bigg(& \lambda^{LMP}_{h,i_k} \cdot gopt_{h,k} + \sum_w \lambda^{SEC}_{w,h,k} \cdot cpfs^S_{w,h,k} + \sum_w \lambda^{REC}_{w,h,k} \cdot recs_{w,h,k} \\ & - GVC_{h,k} \cdot gopt_{h,k} - CTAX \cdot GER_k \cdot gopt_{h,k} \Bigg)\end{aligned} \tag{5}$$

where $\lambda^{SEC}_{w,h,k}$ is the price of the bilateral power contract between GenCO k and load serving entity w at hour h, $\lambda^{REC}_{w,h,k}$ denotes the hourly price of the bilateral REC contract between k and w, and $CTAX$ is the carbon price. The GenCO's objective is subject to several constraints. Based on equation (6), GenCOs in California must sell their power output to the state load serving entity through specified energy contracts:

$$gopt_{h,k} = cpfs^S_{CA,h,k} \quad \forall h, k \in K_{CA} \tag{6}$$

Equation (7) is the generation capacity limit, accounting for forced outage rates and (in the case of intermittent sources) hydro, wind, or solar availability:

$$gopt_{h,k} \leq GNPL_k \cdot GHAV_{h,k} \quad \forall h, k \in K_{CA} \tag{7}$$

Equation (8) limits the total amount of RECs sold to be lower than power generation:

$$\sum_w recs_{w,h,k} \leq gopt_{h,k} \quad \forall h, k \in K_{CA} \tag{8}$$

Finally, the GenCO's problem is subject to non-negativity constraints on the specified energy contracts sold $cpfs^S_{w,h,k}$, power output $gopt_{h,k}$, REC contracts sold $recs_{w,h,k}$, unit commitment and minimum up/down time constraints (not shown).

The objective of GenCOs outside of California ($k \notin K_{CA}$) is given by:

$$\begin{aligned}\sum_h HW_h \cdot \Bigg(& \lambda^{LMP}_{h,i_k} \cdot gopt_{h,k} + \sum_w \lambda^{SEC}_{w,h,k} \cdot cpfs^S_{w,h,k} + \lambda^{UEC}_h \cdot cpfs^U_{h,k} + \sum_w \lambda^{REC}_{w,h,k} \cdot recs_{w,h,k} \\ & - GVC_{h,k} \cdot gopt_{h,k} \Bigg)\end{aligned} \tag{9}$$

where λ^{UEC}_h is the hourly price at which k sells its unspecified power to the pool. Unlike the GenCOs in California, electricity producers in the rest of WECC can also sell unspecified power and are not subject to the carbon policy. As a result, equation (6) is modified as follows:

$$gopt_{h,k} = \sum_w cpfs^S_{w,h,k} + cpfs^U_{h,k} \quad \forall h, k \notin K_{CA} \tag{10}$$

The objective is also subject to a generation capacity constraint (like equation (7), but applied to $k \notin K_{CA}$) and a limit on the total amount of RECs sold (like equation (8), but applied to $k \notin K_{CA}$). Finally, the GenCO's problem is subject to non-negativity constraints on the energy contracts sold $cpfs^S_{w,h,k}$ and $cpfs^U_{h,k}$, power output $gopt_{h,k}$, REC contracts sold $recs_{w,h,k}$, unit commitment and minimum up/down time constraints (not shown).

III. Load Serving Entities

Each load serving entity (LSE) w in JHSMINE corresponds to one state in the U.S. (or province in Canada). LSEs serve load by purchasing energy from the SO at the nodal price, and all load served must be bought through specified contracts or from the unspecified pool. Thus, for each MW bought a LSE pays the price of the contract (λ^{SEC} or λ^{UEC}) and the energy price at its node (λ^{LMP}). In addition, the LSE buys RECs to meet its RPS obligation, or pays a penalty for noncompliance. As for the GenCOs, we present the problem of the California LSE ($w = CA$) and LSEs in the rest of WECC separately, because only the former is subject to the cap-and-trade program and pays for the emissions associated with power imports.

The objective of the California LSE ($w = CA$) is to minimize the cost of serving inelastic electricity demand, which includes the cost of energy bought from the electricity market, specified power contracts, unspecified power, renewable energy contracts, unserved energy, noncompliance with the RPS policy, and imported emissions:

$$\sum_h HW_h \cdot \Bigg[\sum_{i \in I_w} \lambda^{LMP}_{h,i} \left(LOAD_{h,i} - n^{Load}_{h,i}\right) + \sum_k \lambda^{SEC}_{w,h,k} \cdot cpfb^S_{w,h,k} + \lambda^{UEC}_h \cdot cpfb^U_{w,h} + \sum_k \lambda^{REC}_{w,h,k} \cdot recb_{w,h,k}$$
$$+ \sum_{i \in I_w} VOLL \cdot n^{Load}_{h,i} + ACP_w \cdot n^{RPS}_{w,h} + CTAX \cdot \left(\sum_{k \notin K_w} DR^S_{w,k} \cdot cpfb^S_{w,h,k} + DR^U_w \cdot cpfb^U_{w,h}\right)\Bigg] \quad (11)$$

Constraints (12)-(17) apply for $w = CA$. Based on equation (12), the LSE must buy power directly from GenCOs k or from the unspecified power pool:

$$\sum_k cpfb^S_{w,h,k} + cpfb^U_{w,h} = \sum_{i \in I_w} \left(LOAD_{h,i} - n^{Load}_{h,i}\right) \quad \forall h \quad (12)$$

The California LSE also faces a RPS constraint:

$$\sum_h HW_h \cdot \left(n^{RPS}_{w,h} + \sum_k RE_{w,k} \cdot recb_{w,h,k}\right) \geq RPS_w \cdot \left(\sum_h HW_h \sum_{i \in I_w} \left(LOAD_{h,i} - n^{Load}_{h,i}\right)\right) \quad (13)$$

Equation (14) sets a lower bound on the renewable energy coming from resources within California and/or in states directly adjacent to California (Official California Legislative Information, 2015):

$$\sum_h HW_h \cdot \left(n^{RPS}_{w,h} + \sum_{\substack{k \in K_{CA} \\ \cup K_{OR} \\ \cup K_{NV} \\ \cup K_{AZ}}} RE_{w,k} \cdot recb_{w,h,k}\right) \geq RES_{CA} \cdot RPS_w \cdot \left(\sum_h HW_h \sum_{i \in I_w} \left(LOAD_{h,i} - n^{Load}_{h,i}\right)\right) \quad (14)$$

where RES_{CA} is the minimum annual share of renewable energy supplied to the California grid, located within or proximate to the state. To make sure that the level and composition of power imports to California in JHSMINE are comparable to historical values, we take two steps. First, we introduce a constraint on the annual share of specified imports over total power imports to California:

$$\sum_h HW_h \cdot \left(\sum_{k \notin K_w} cpfb^S_{w,h,k}\right) = SSI_y \cdot \sum_h HW_h \left(\sum_{k \notin K_w} cpfb^S_{w,h,k} + cpfb^U_{w,h}\right) \quad (15)$$

Second, we introduce constraints on the share of California imports by fossil fuel generation type. For specified generation from natural gas ($f = NG$), the constraint is:

$$\sum_h HW_h \left(\sum_{\substack{k \in K_{NG} \\ k \notin K_w}} cpfb^S_{w,h,k} \right) = SSI_{f,y} \cdot \sum_h HW_h \left(\sum_{k \notin K_w} cpfb^S_{w,h,k} + cpfb^U_{w,h} \right) \tag{16}$$

where K_{NG} refers to natural gas-fired generators, and $SSI_{f,y}$ is the fuel-specific annual share of imports. For specified generation from coal and oil products ($f = CO$), the constraint is:

$$\sum_h HW_h \left(\sum_{\substack{k \in K_{CO} \\ k \notin K_w}} cpfb^S_{w,h,k} \right) = SSI_{f,y} \cdot \sum_h HW_h \left(\sum_{k \notin K_w} cpfb^S_{w,h,k} + cpfb^U_{w,h} \right) \tag{17}$$

where K_{CO} refers to coal- and oil-fired generators. Finally, the LSE's problem is subject to non-negativity constraints on the contracts bought $cpfb^S_{w,h,k}$ and $cpfb^U_{w,h}$, the load shedding amount $n^{Load}_{h,i}$, REC contracts bought $recb_{w,h,k}$, and non-compliance amount with RPS policy $n^{RPS}_{w,h}$.

The objective of LSEs in the rest of WECC ($w \neq CA$) is given by:

$$\sum_h HW_h \cdot \left[\sum_{i \in I_w} \lambda^{LMP}_{h,i} \left(LOAD_{h,i} - n^{Load}_{h,i} \right) + \sum_k \lambda^{SEC}_{w,h,k} \cdot cpfb^S_{w,h,k} + \lambda^{UEC}_h \cdot cpfb^U_{w,h} + \sum_k \lambda^{REC}_{w,h,k} \cdot recb_{w,h,k} \right.$$
$$\left. + \sum_{i \in I_w} VOLL \cdot n^{Load}_{h,i} + ACP_w \cdot n^{RPS}_{w,h} \right] \tag{18}$$

Unlike the California LSE, load serving entities in the rest of WECC do not incur a cost of imported emissions (i.e., last term in (11)). The LSEs must buy specified or unspecified power (equation (12)) and are subject to RPS constraints (equation (13)), plus non-negativity constraints on the contracts bought $cpfb^S_{w,h,k}$ and $cpfb^U_{w,h}$, the load shedding amount $n^{Load}_{h,i}$, REC contracts bought $recb_{w,h,k}$, and non-compliance amount with RPS policy $n^{RPS}_{w,h}$.

IV. Market Clearing Conditions

Market clearing conditions for electricity ensure that hourly demand equals supply at each location in the network, and the associated dual variable presents the nodal electricity price $\lambda^{LMP}_{h,i}$:

$$\sum_{k \in K_i} gopt_{h,k} + \sum_{l \in L^{In}_i} pf_{l,h} - \sum_{l \in L^{Out}_i} pf_{l,h} = LOAD_{h,i} - n^{Load}_{h,i} \quad \forall h, i \tag{19}$$

There are two clearing conditions for the contract market. First, the unspecified power sold from GenCOs equals the amount by the LSEs at every hour. The associated dual variable is the price of unspecified power at hour h, λ^{UEC}_h:

$$\sum_k cpfs^U_{h,k} = \sum_w cpfb^U_{w,h} \quad \forall h \tag{20}$$

Second, for every bilateral contract between GenCO k and LSE w at hour h, demand must equal supply equation (21). The associated dual variable is the price of the specified energy contract $\lambda^{SEC}_{w,h,k}$:

$$cpfs^S_{w,h,k} = cpfb^S_{w,h,k} \quad \forall w, h, k \tag{21}$$

Finally, since emission allowances and RECs are unbundled in the current formulation of JHSMINE, a REC market clearing is given by equation (22). The corresponding price variable is $\lambda^{REC}_{w,h,k}$.

$$recs_{w,h,k} = recb_{w,h,k} \quad \forall w, h, k \tag{22}$$

V. Nomenclature

Sets and indices

Set	Description	Index
F	Fuel type	f
H	Hour	h
I	Node	i
K	Generation company/Generator	k
L	Transmission line	l
Y	Year	y
W	Load serving entity/state or province	w
Subset	**Description**	
$K_f \subset K$	Generator of fuel type f	
$K_i \subset K$	Generator connected to bus i	
$K_w \subset K$	Generator in state w	
$L^{DC} \subset L$	HVDC transmission line	
$L_i^{In} \subset L$	Transmission line entering bus i	
$L_i^{Out} \subset L$	Transmission line leaving bus i	
Special Index	**Description**	
i_k	Node where generator k is located	
i_l^{From}	Sending node of transmission line l	
i_l^{To}	Receiving node of transmission line l	
w_k	State where generator k is located	

Parameters

	Description	Unit (or Value)
ACP_w	Alternative compliance penalty of RPS	\$/MWh
BP	Base power of the per unit transmission system	100 MW
B_l	Susceptance of transmission line l	p.u.
$CTAX$	Carbon price in California	\$/ton
$DR^S_{w,k}$	Deemed emission rate assumed for the energy credit contract between the state-level LSE w and generator k	ton/MWh
DR^U_w	Default emission rate for unspecified power	0.428 ton/MWh
GER_k	Emission rate of generator k	ton/MWh
$GHAV_{k,h}$	Hourly availability of generator k in hour h	fraction of capacity
$GNPL_k$	Nameplate capacity of generator k	MW
$GVC_{k,h}$	Variable cost of generator k, including fuel and variable O&M cost	\$/MWh
HW_h	Number of hours represented by hour h	hour
LTM_l	Line Rating (or thermal limit) of transmission line l	MW
$RE_{w,k}$	Renewable eligibility; 1 if generator k is considered as renewable in state w	0 or 1
RES_{CA}	Renewable energy share supplied to the California grid, located within or proximate to the state	fraction of RPS requirement
RPS_w	RPS of state w	fraction of demand
SSI_y	share of specified imports over total CA imports in year y	%
$SSI_{f,y}$	share of specified imports by fuel f over total CA imports in year y	%
$VOLL$	Value of lost load	\$/MWh

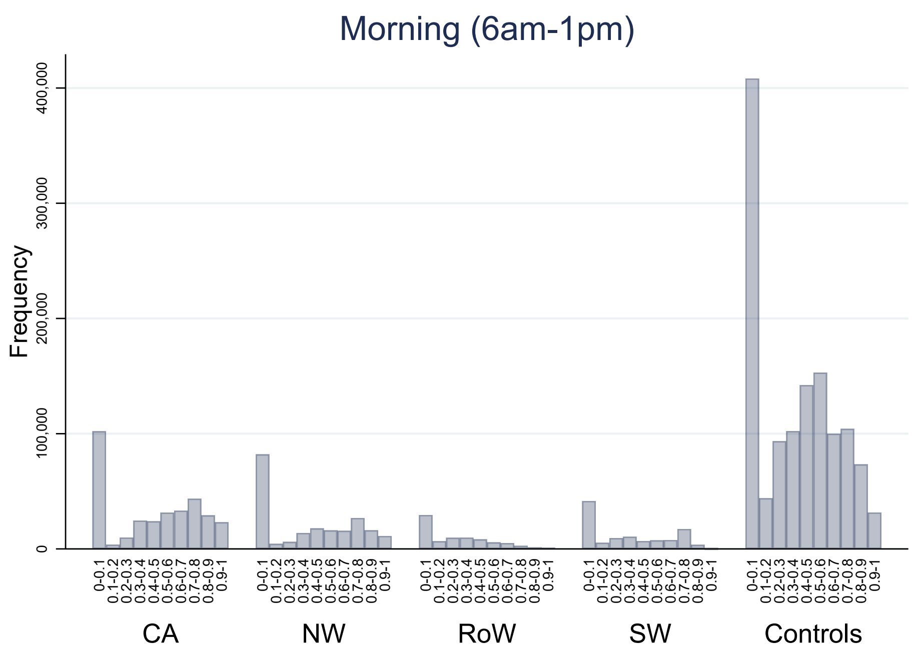
Variables

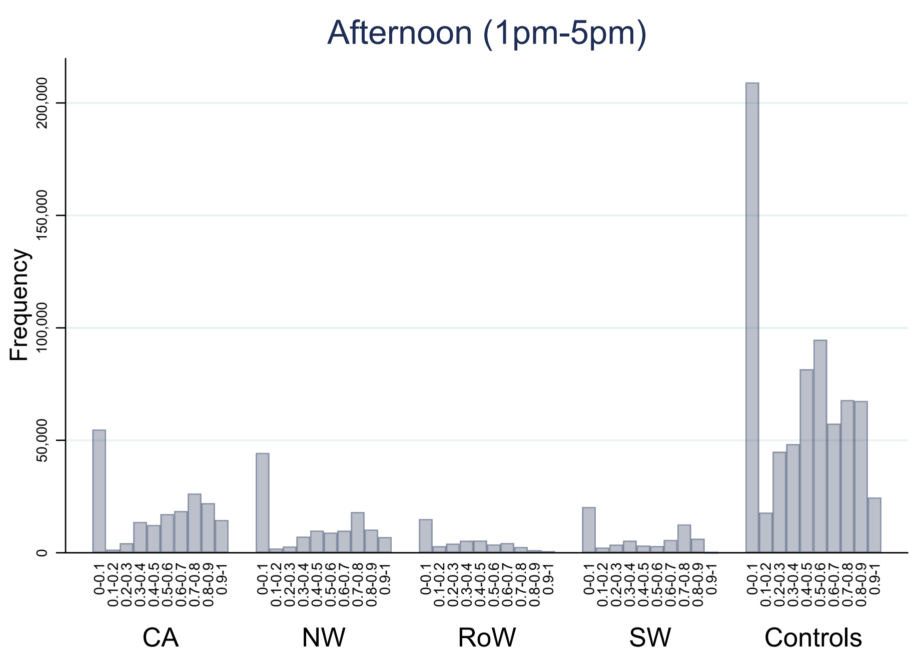
	Description	Unit
$cpfb^U_{w,h}$	Unspecified contract bought by state w at hour h (≥ 0)	MW
$cpfs^U_{h,k}$	Unspecified contract sold by generator k at hour h (≥ 0)	MW
$cpfb^S_{w,h,k}$	Specified contract bought by state-level LSE w from generator k at hour h (≥ 0)	MW
$cpfs^S_{w,h,k}$	Specified contract sold by generator k to state-level LSE w at hour h (≥ 0)	MW
$gopt_{h,k}$	Power output of generator k at hour h (≥ 0)	MW
$n^{load}_{h,i}$	Load shedding at bus i at hour h (≥ 0)	MW
$n^{rps}_{h,w}$	Noncompliance with RPS policy (≥ 0)	MW
pf_l	Power flow on transmission line l at hour h (unrestricted)	MW
$recb_{w,h,k}$	REC contract bought by the state LSE w from generator k at hour h (≥ 0)	MW
$recs_{w,h,k}$	REC contract sold to the state LSE w by generator k at hour h (≥ 0)	MW
$\theta_{h,i}$	Voltage angle of bus i at hour h	radian
λ	Dual variables: shadow prices of the constraints; the meaning and the units depend on the super/subscripts	-

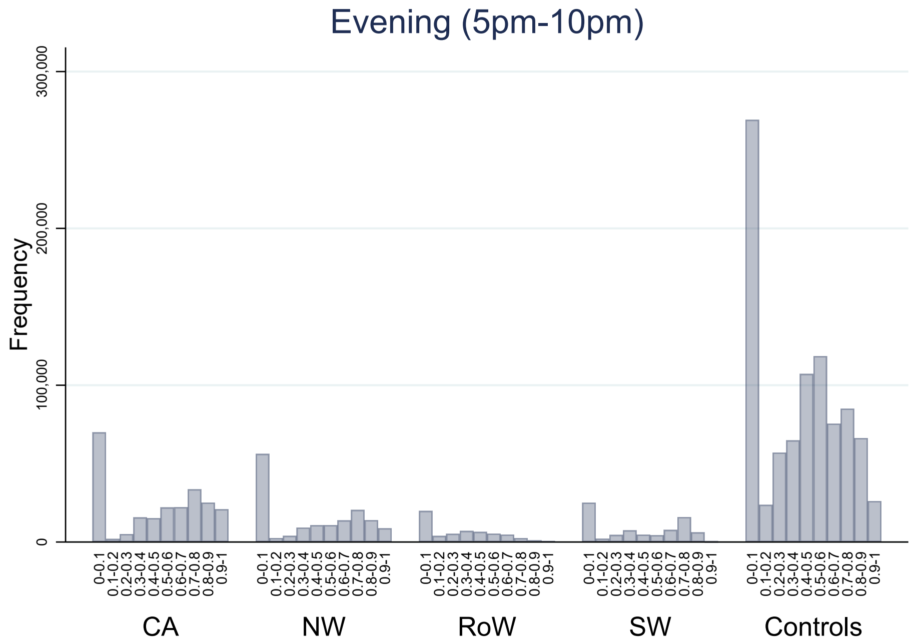
B. Figures

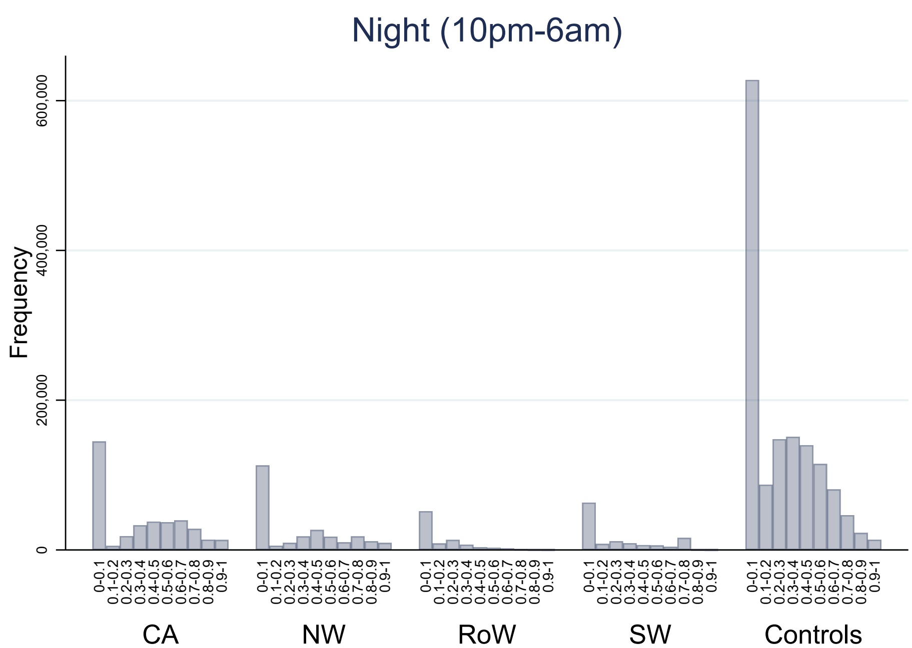
Figure A1: Frequency histograms of 2009-10 average capacity factors by technology, region and block of hour

(a) NGCC

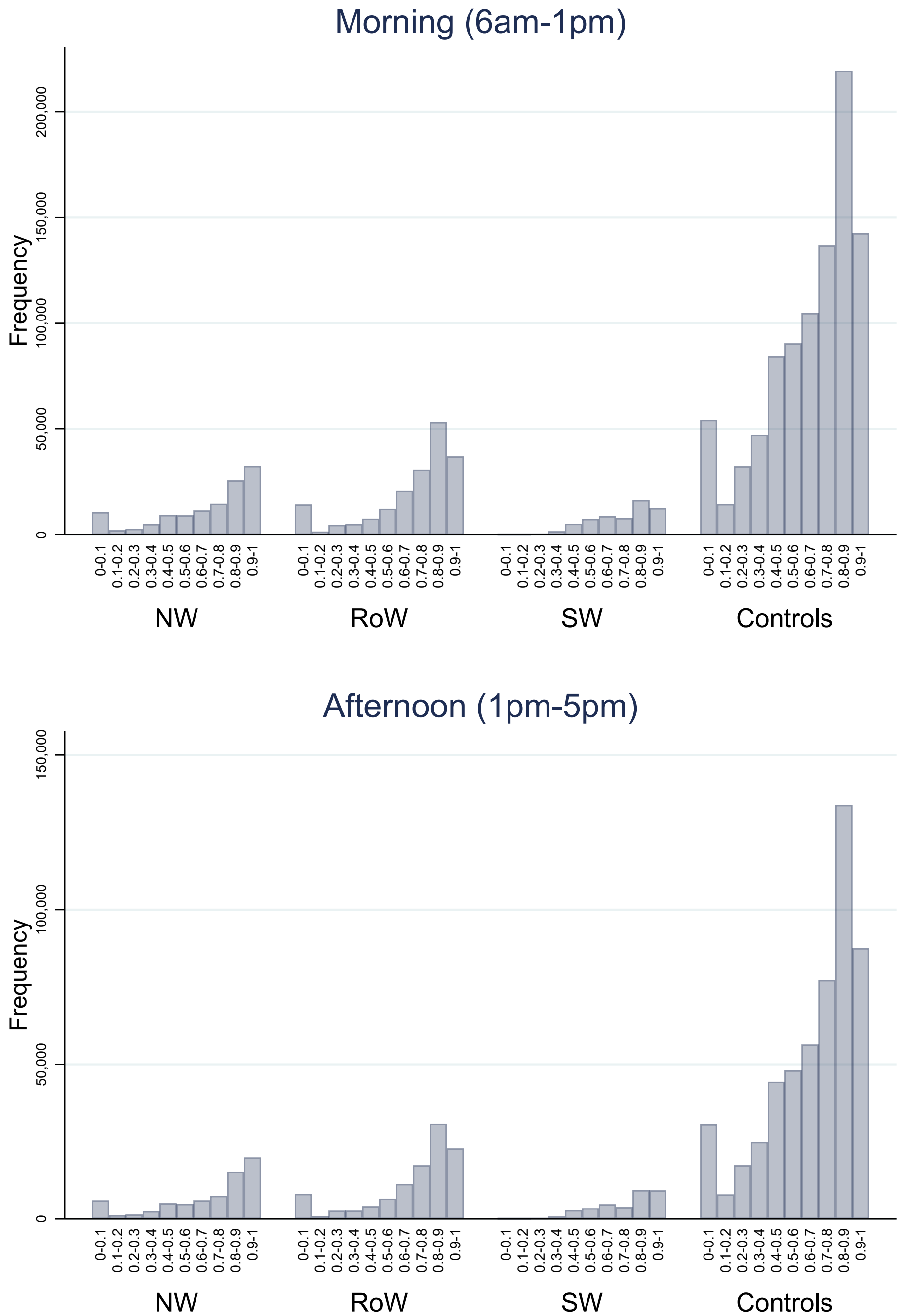


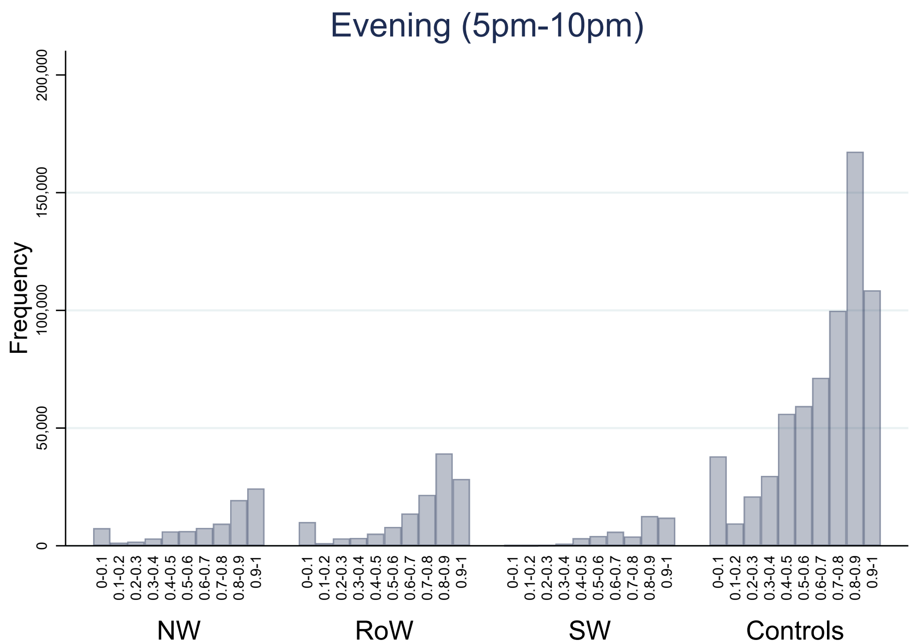



Evening (5pm-10pm)
Frequency
0
100,000
200,000
300,000
0-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-1
CA
NW
RoW
SW
Controls


Night (10pm-6am)
Frequency
0
200,000
400,000
600,000
0-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-1
CA
NW
RoW
SW
Controls

(b) Coal


Morning (6am-1pm)
Frequency
0
50,000
100,000
150,000
200,000
0-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-1
NW
RoW
SW
Controls
Afternoon (1pm-5pm)
Frequency
0
50,000
100,000
150,000
NW
RoW
SW
Controls


Evening (5pm-10pm)
Frequency
0
50,000
100,000
150,000
200,000
0-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-1
NW
RoW
SW
Controls

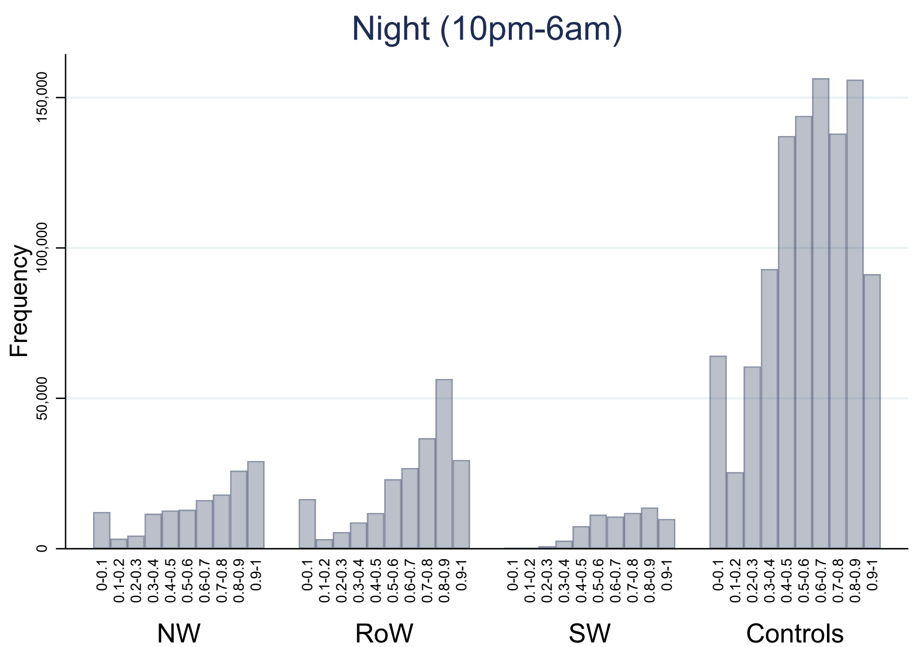
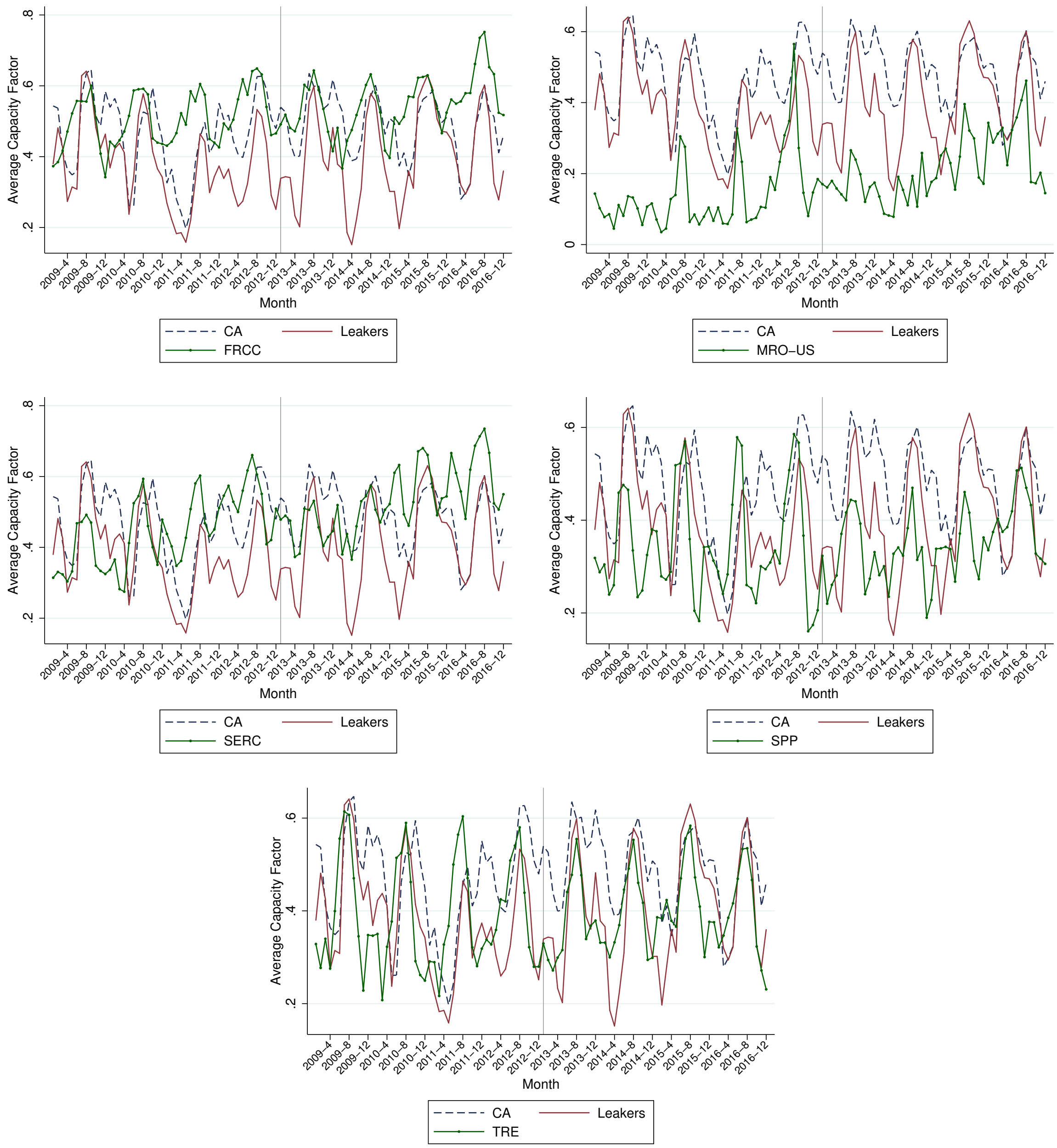

Night (10pm-6am)
Frequency
0
50,000
100,000
150,000
0-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-1
NW
RoW
SW
Controls

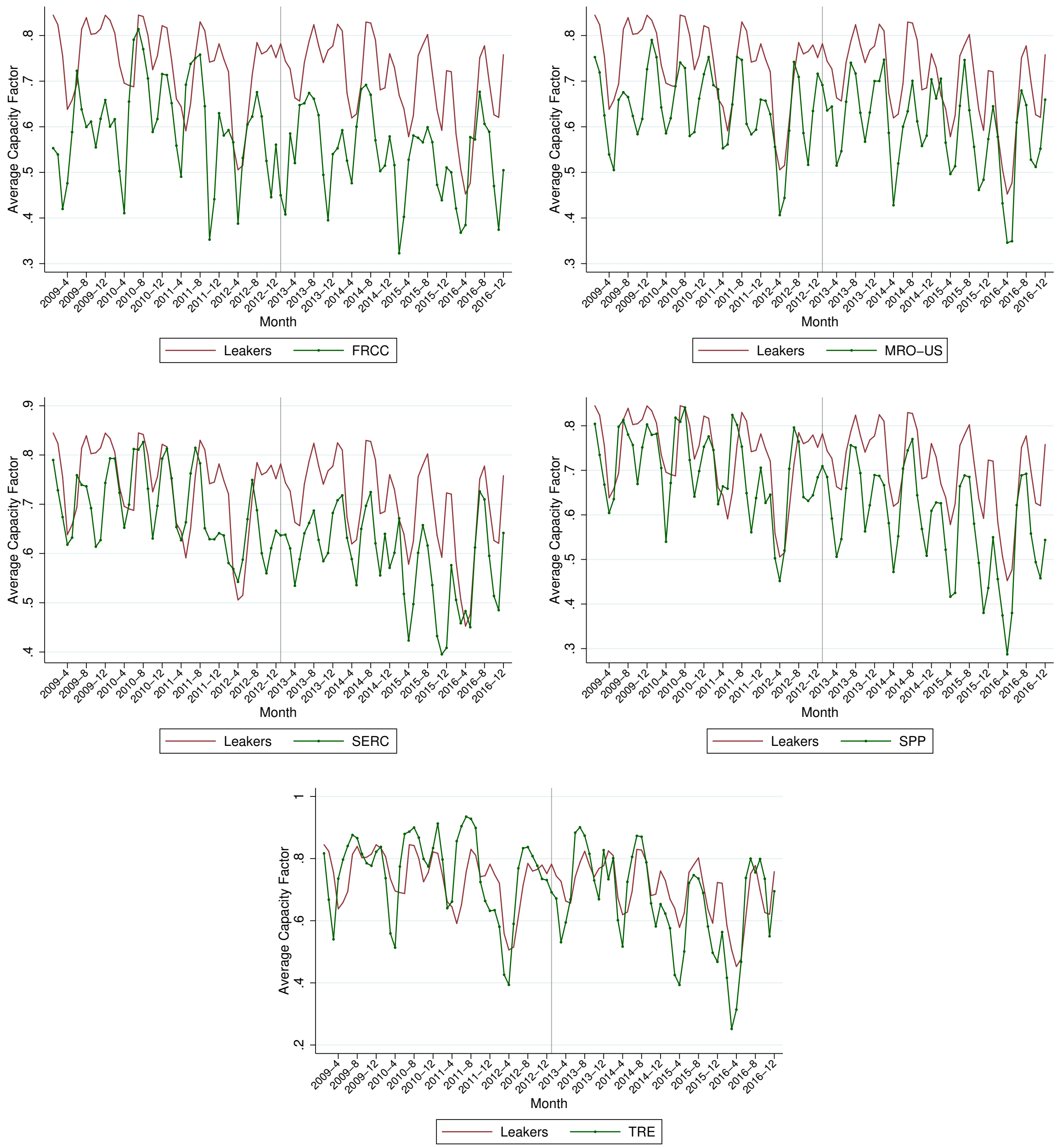
Figure A2: Capacity factor trajectories of matched treated and control plants by region

(a) NGCC



Note: The vertical line indicates the starting point for policy implementation.

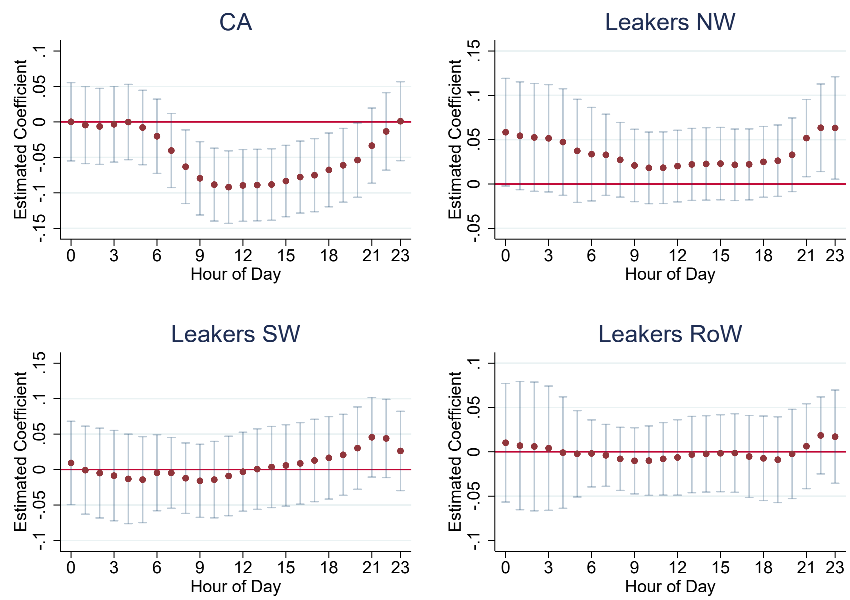
(b) Coal



Note: The vertical line indicates the starting point for policy implementation.

Figure A3: Treatment heterogeneity by hour of day based on specification (6)

(a) NGCC



(b) Coal

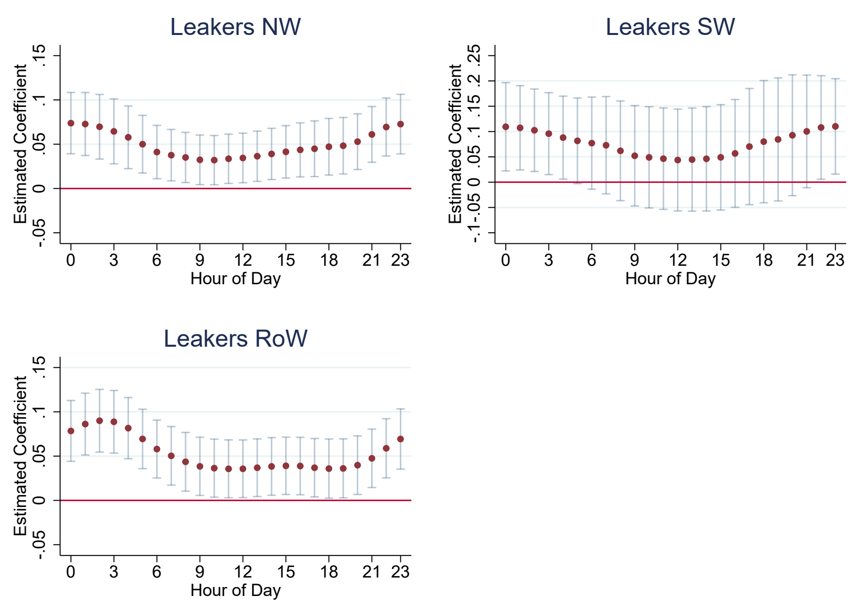
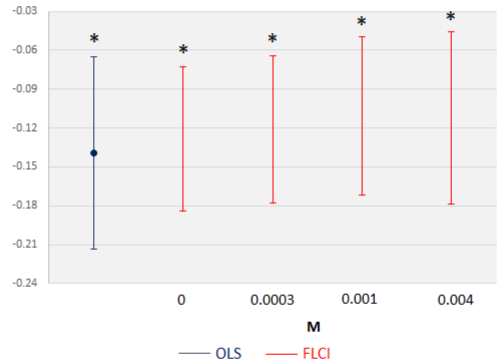


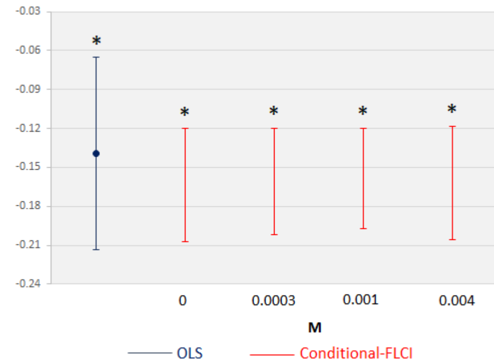
Figure A4: Estimated policy effect on NGCC plant capacity factors in California (Day): OLS and robust confidence intervals

Jan and Feb 2013

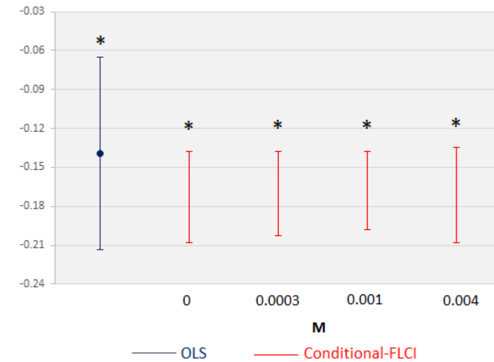
(a) No restrictions



(b) Monotonicity and negative bias

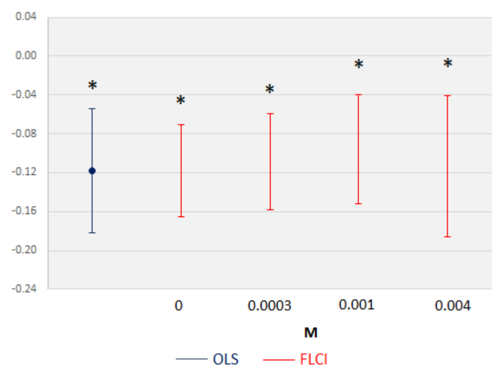


(c) Monotonicity and positive bias

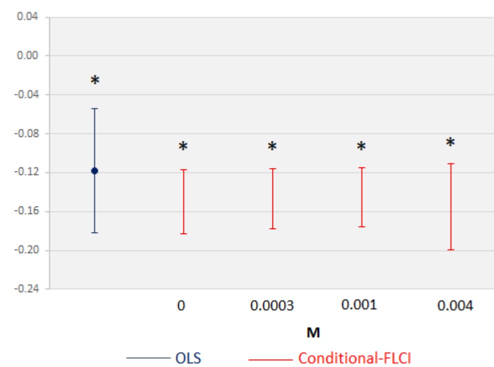


Spring 2013

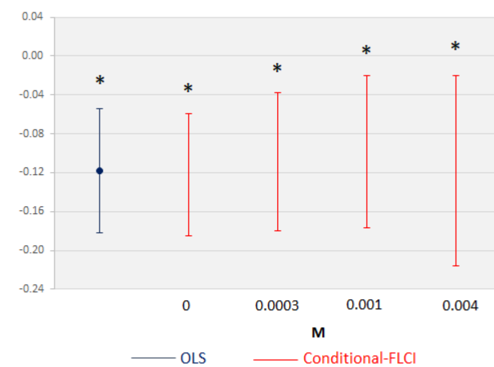
(a) No restrictions



(b) Monotonicity and negative bias

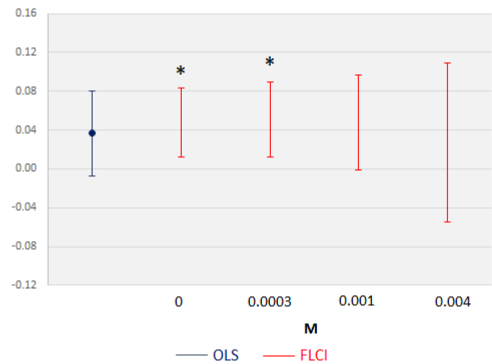


(c) Monotonicity and positive bias

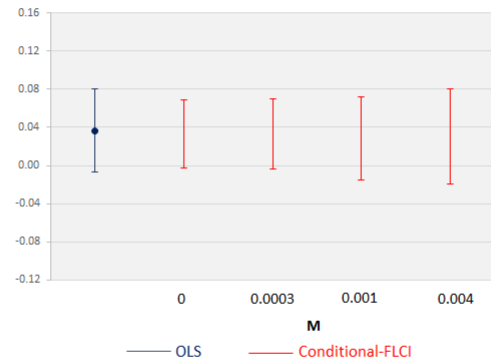


Summer 2013

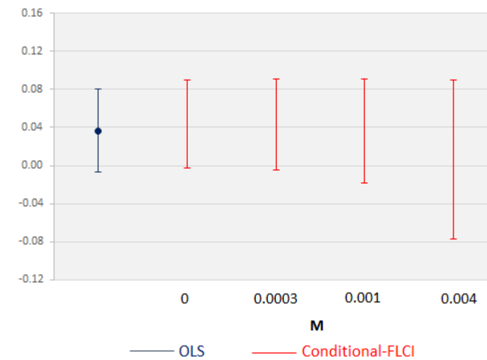
(a) No restrictions



(b) Monotonicity and negative bias

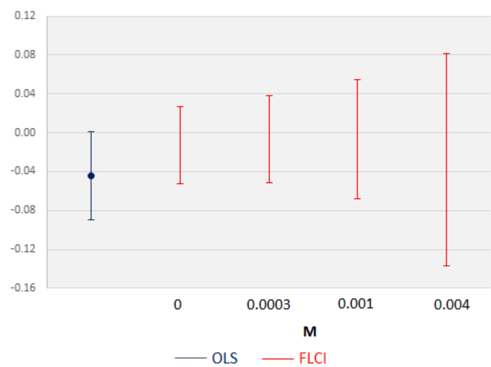


(c) Monotonicity and positive bias

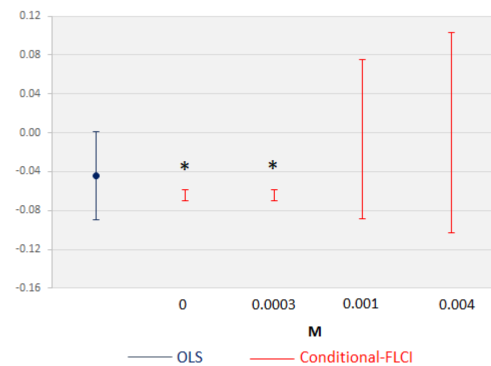


Fall 2013

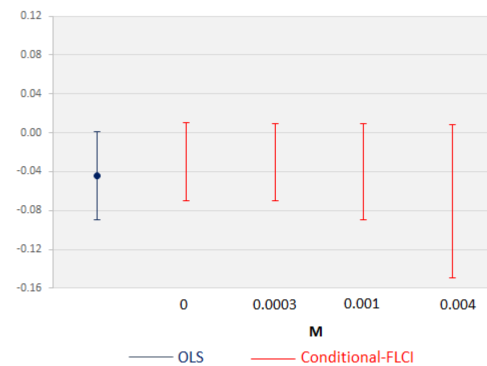
(a) No restrictions



(b) Monotonicity and negative bias



(c) Monotonicity and positive bias



Winter 2013-14

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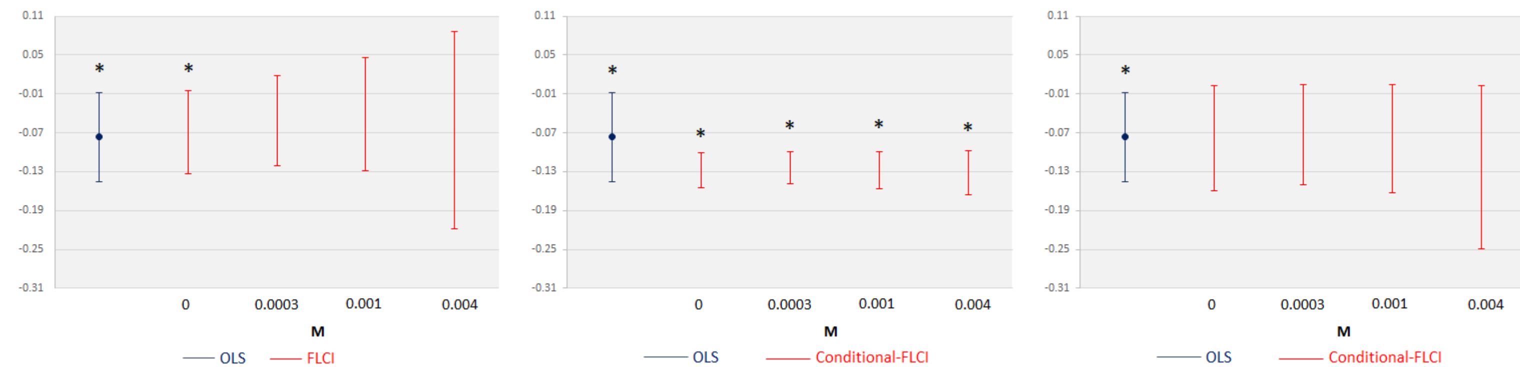
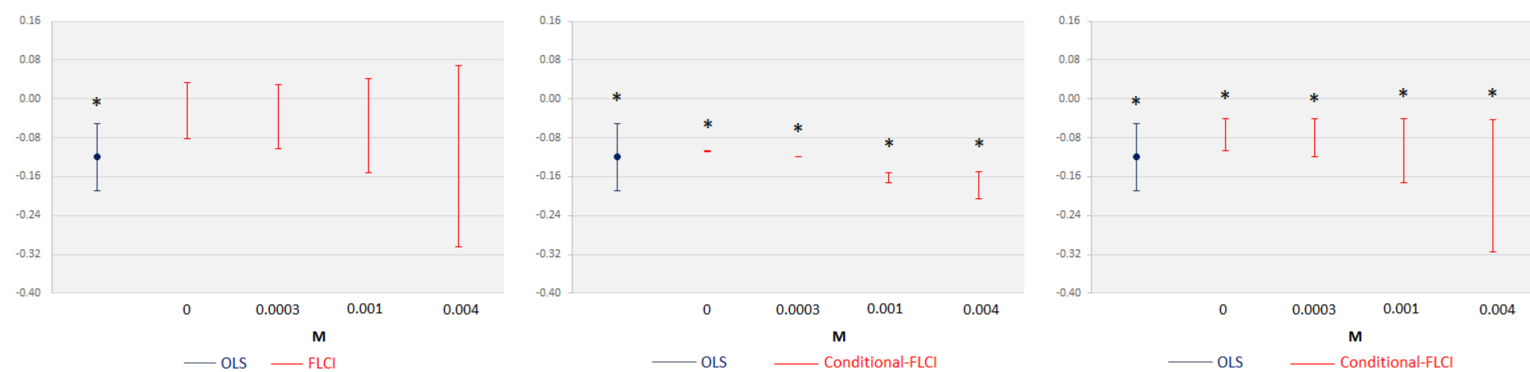


Spring 2014

(a) No restrictions (b) Monotonicity and negative bias (c) Monotonicity and positive bias



Summer 2014

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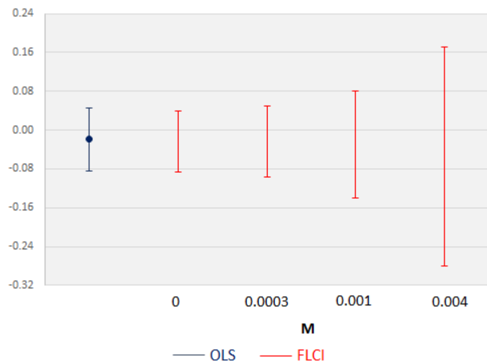

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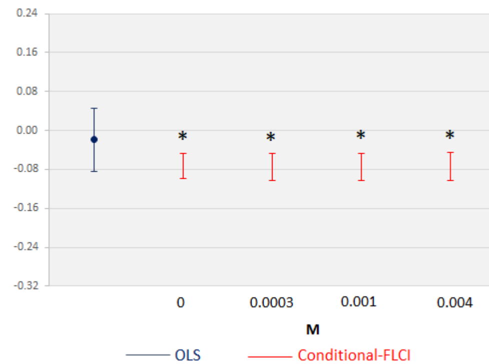

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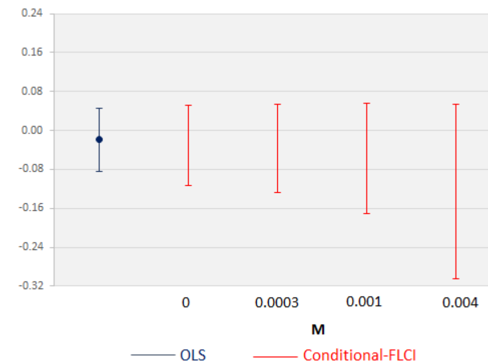
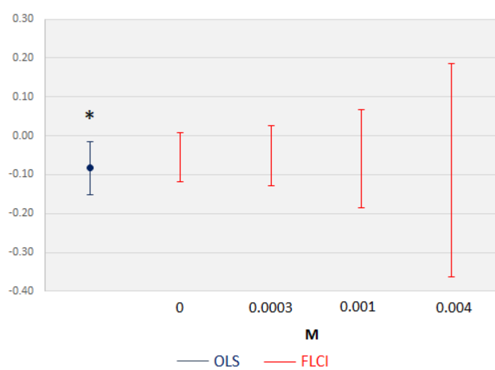


Fall 2014

(a) No restrictions



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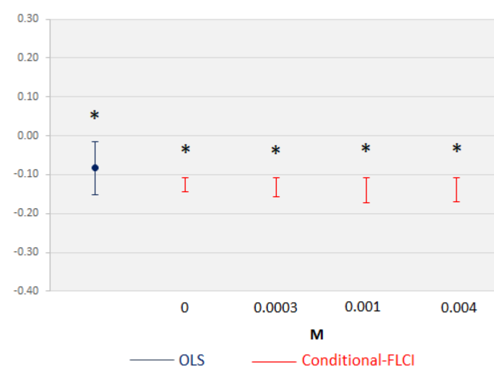
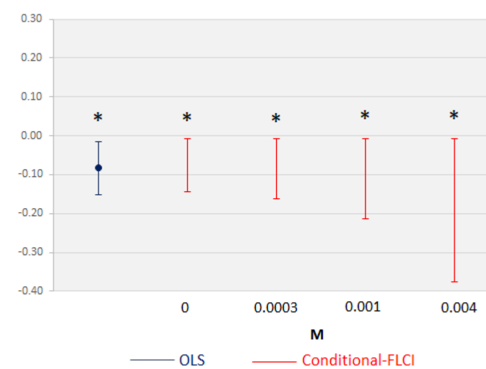
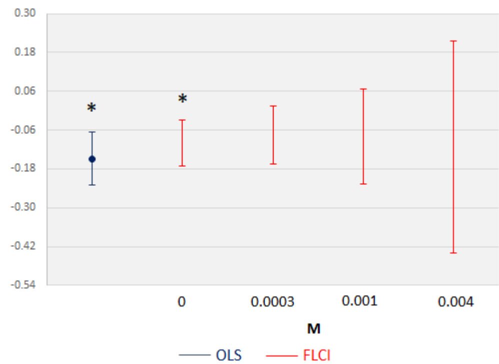


(c) Monotonicity and positive bias

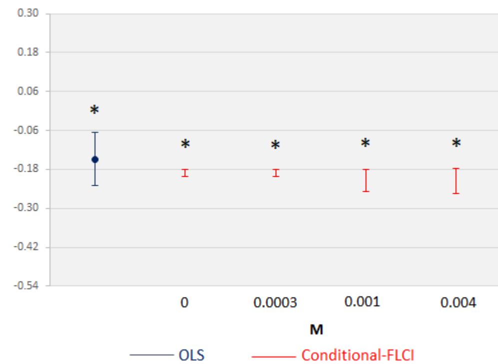


Winter 2014-15

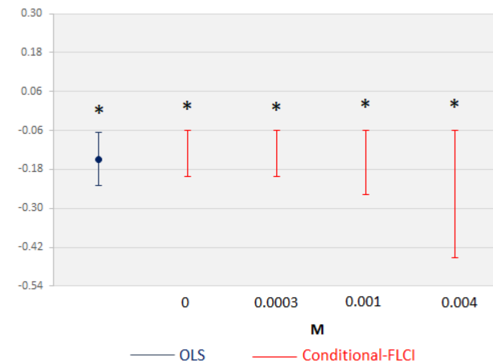
(a) No restrictions



(b) Monotonicity and negative bias

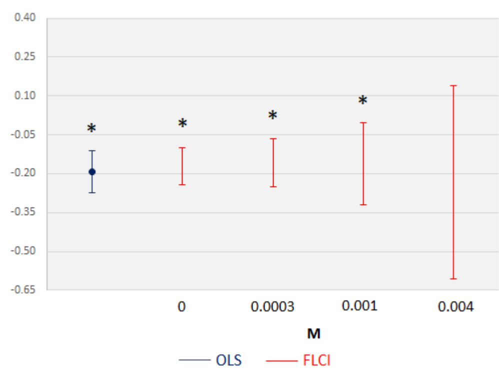


(c) Monotonicity and positive bias

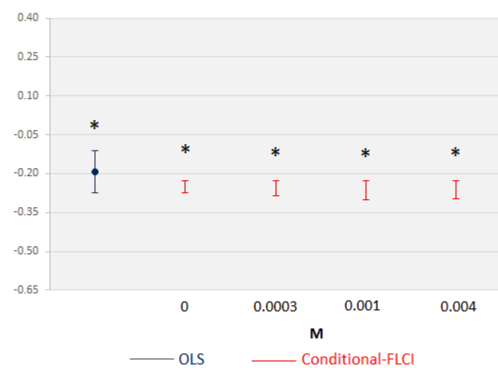


Spring 2015

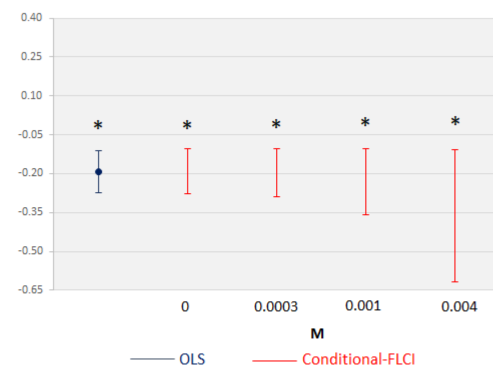
(a) No restrictions



(b) Monotonicity and negative bias

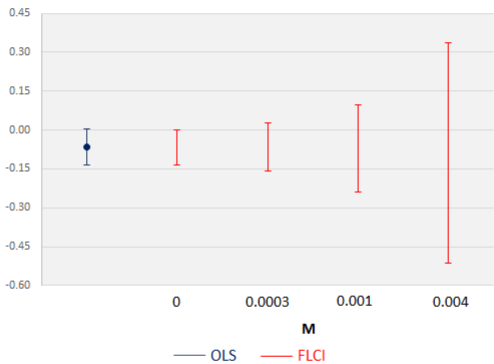


(c) Monotonicity and positive bias

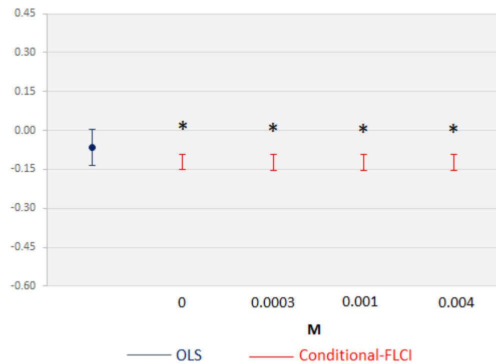


Summer 2015

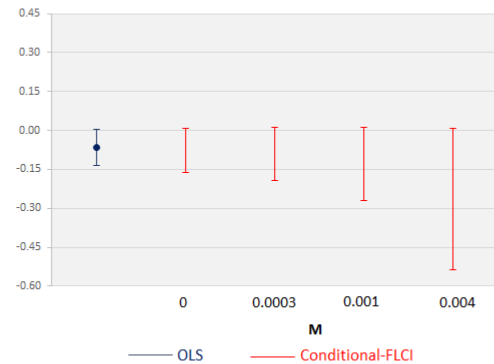
(a) No restrictions



(b) Monotonicity and negative bias

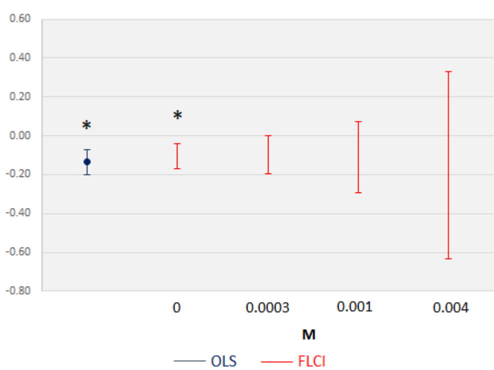


(c) Monotonicity and positive bias

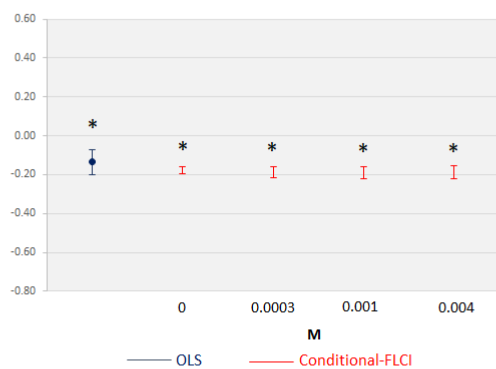


Fall 2015

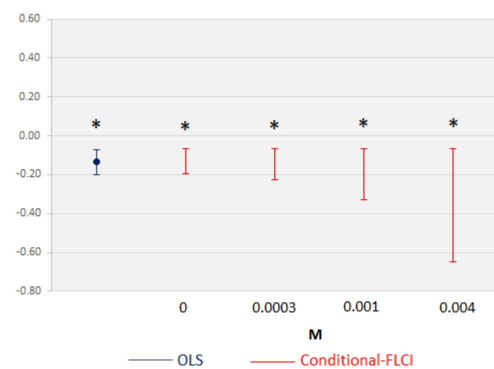
(a) No restrictions



(b) Monotonicity and negative bias

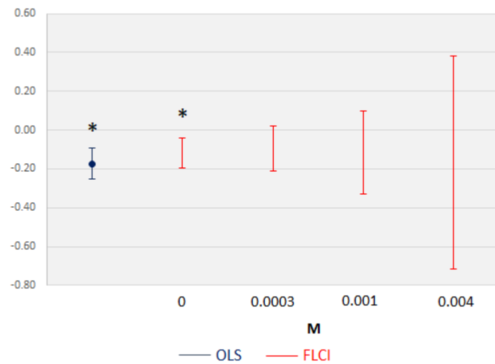


(c) Monotonicity and positive bias

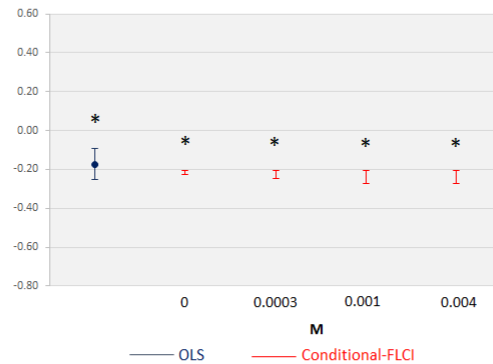


Winter 2015-16

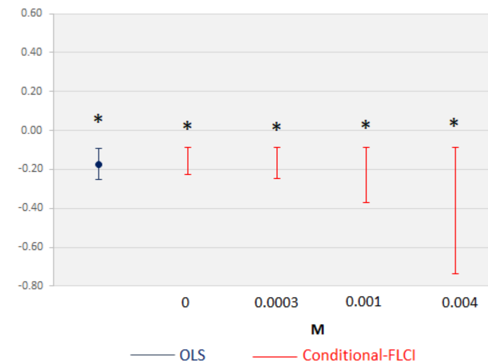
(a) No restrictions



(b) Monotonicity and negative bias

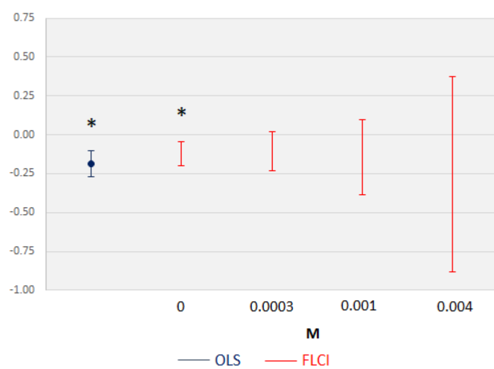


(c) Monotonicity and positive bias

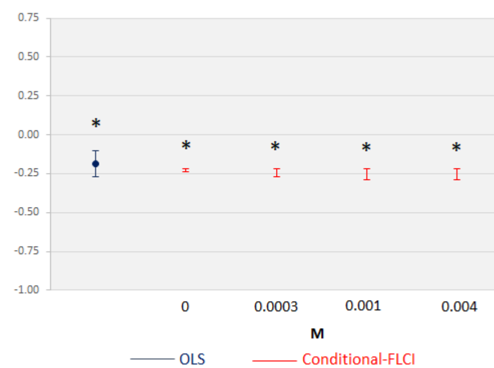


Spring 2016

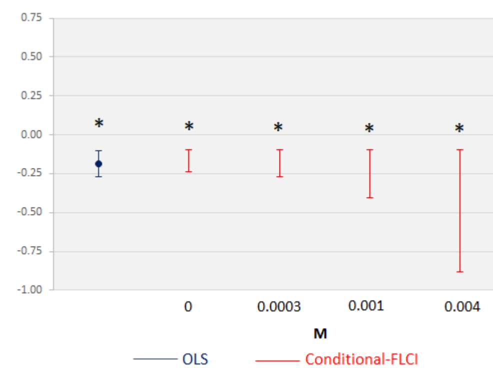
(a) No restrictions



(b) Monotonicity and negative bias

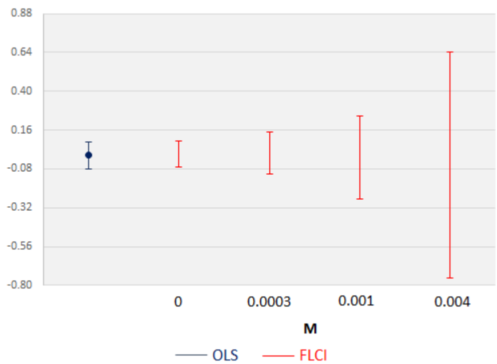


(c) Monotonicity and positive bias

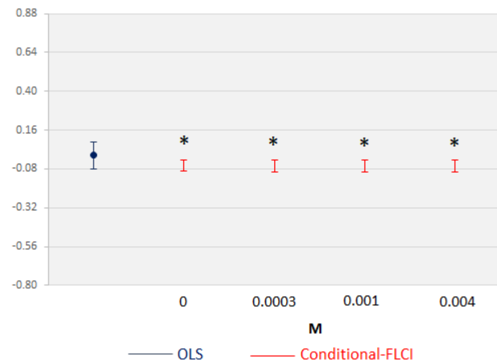


Summer 2016

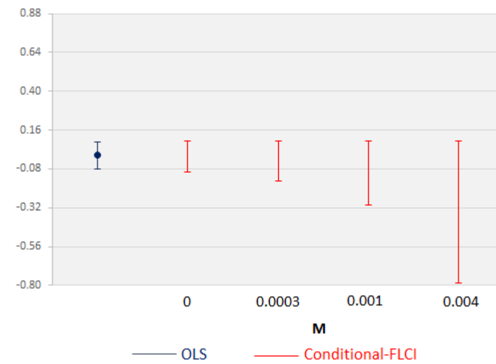
(a) No restrictions



(b) Monotonicity and negative bias

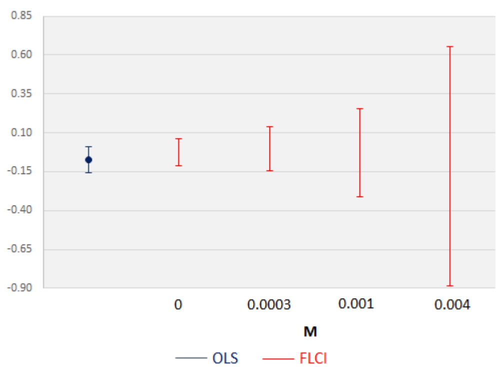


(c) Monotonicity and positive bias

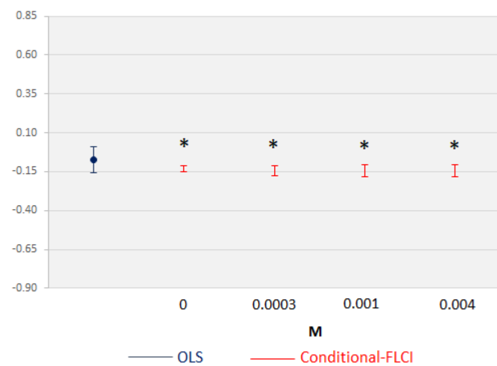


Fall 2016

(a) No restrictions



(b) Monotonicity and negative bias



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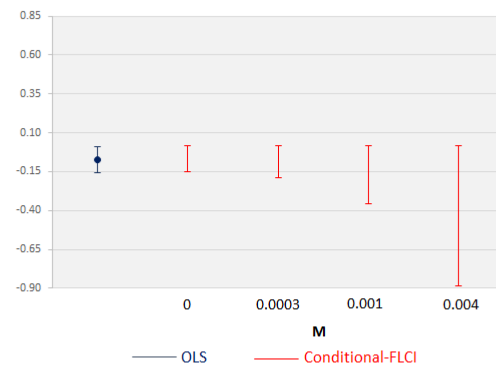
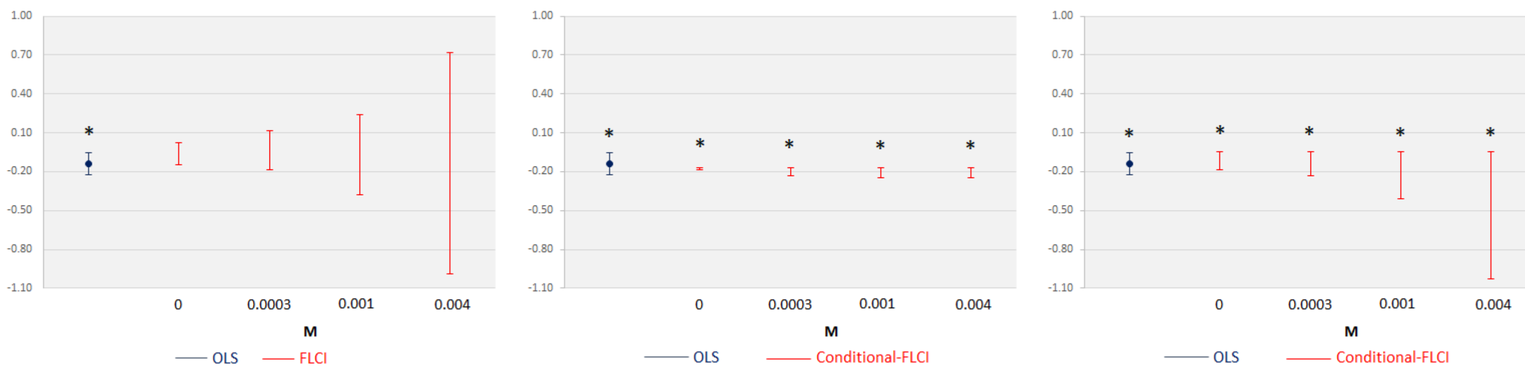


Nov and Dec 2016

(a) No restrictions (b) Monotonicity and negative bias (c) Monotonicity and positive bias

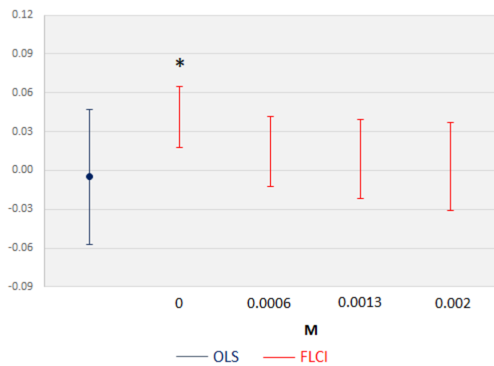


Note: Stars indicate intervals that do not cross zero.

Figure A5: Estimated policy effect on coal-fired plant capacity factors in the Rest of WECC (Day): OLS and robust confidence intervals

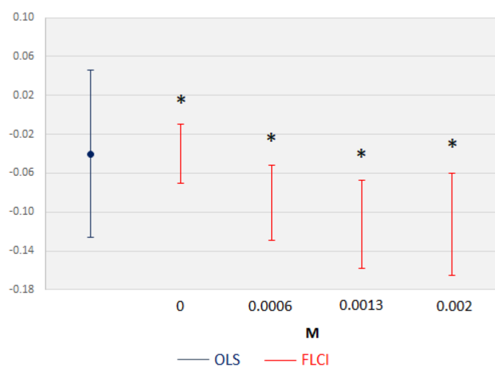
Jan and Feb 2013

(a) No restrictions



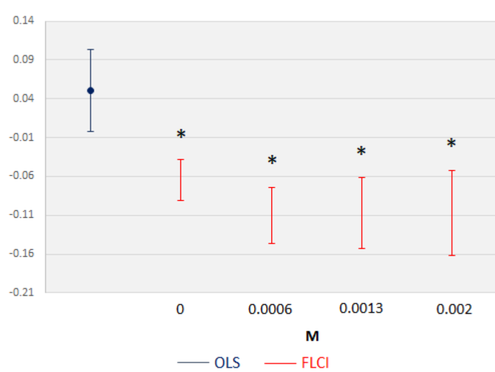
Spring 2013

(a) No restrictions



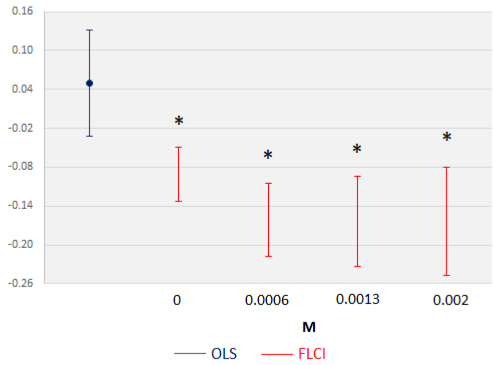
Summer 2013

(a) No restrictions



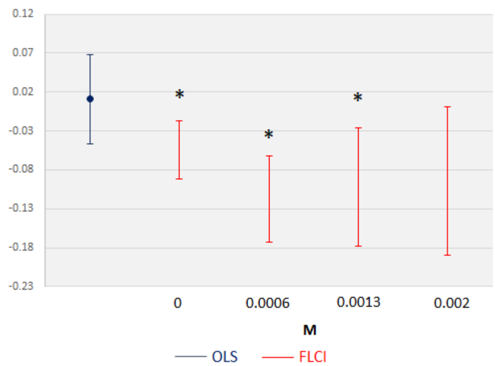
Fall 2013

(b) No restrictions



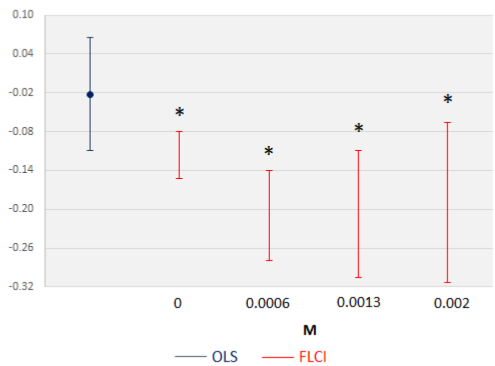
Winter 2013-14

(a) No restrictions



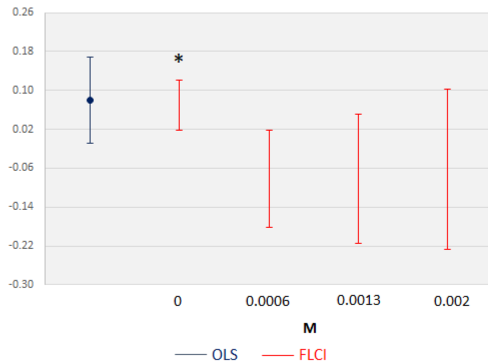
Spring 2014

(a) No restrictions



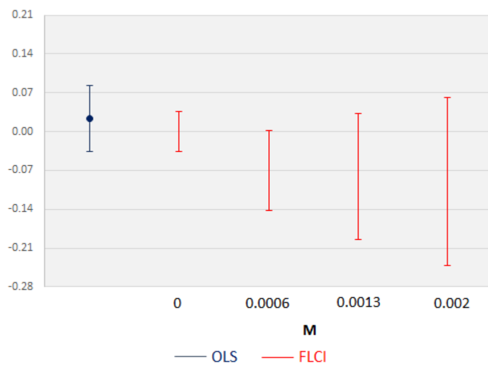
Summer 2014

(b) No restrictions



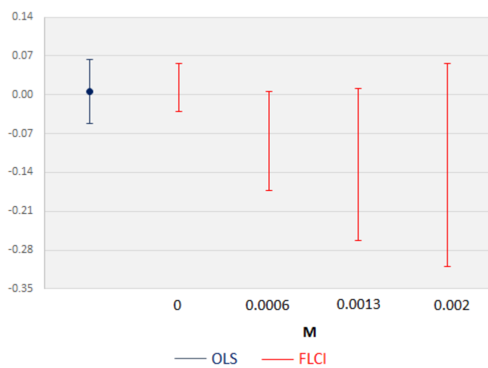
Fall 2014

(a) No restrictions



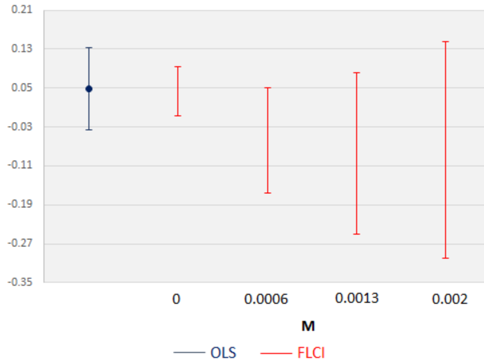
Winter 2014-15

(a) No restrictions



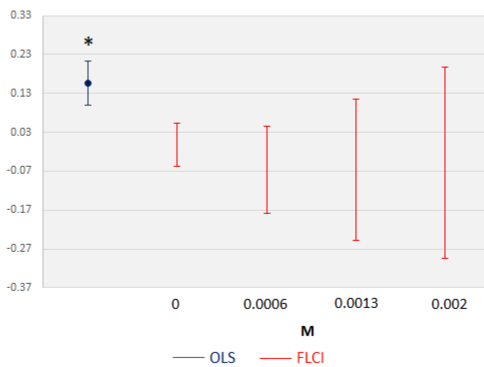
Spring 2015

(b) No restrictions



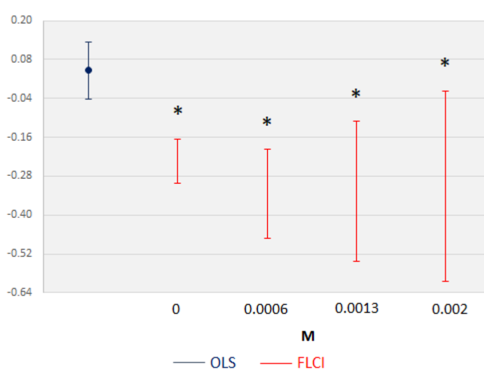
Summer 2015

(a) No restrictions



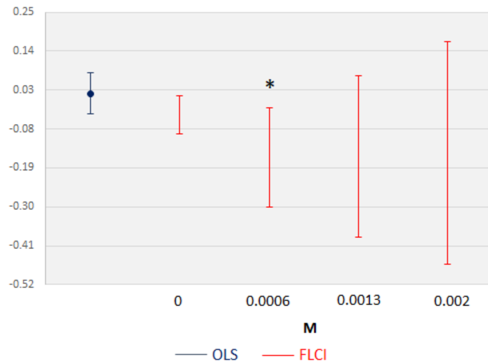
Fall 2015

(a) No restrictions



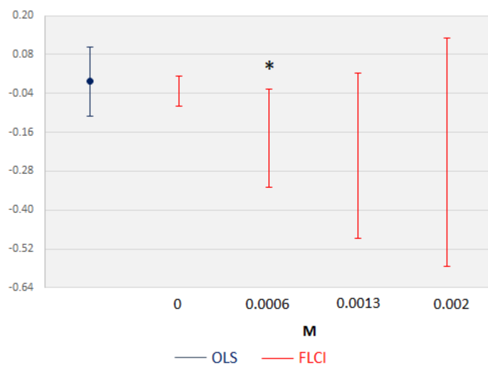
Winter 2015-16

(b) No restrictions



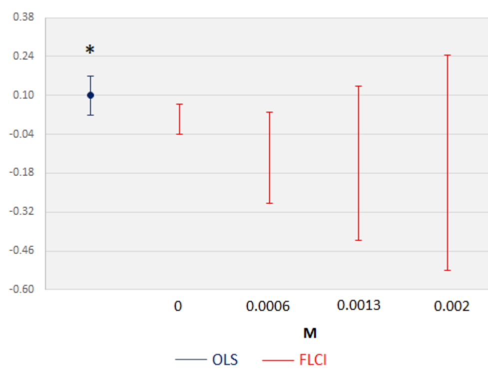
Spring 2016

(a) No restrictions



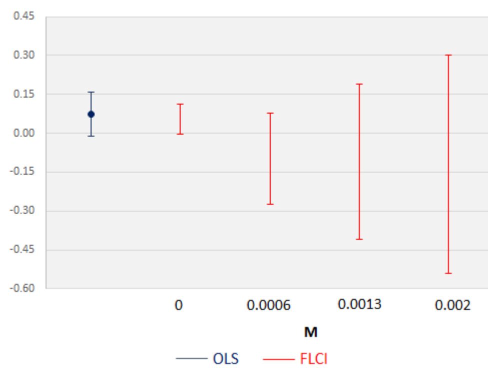
Summer 2016

(a) No restrictions



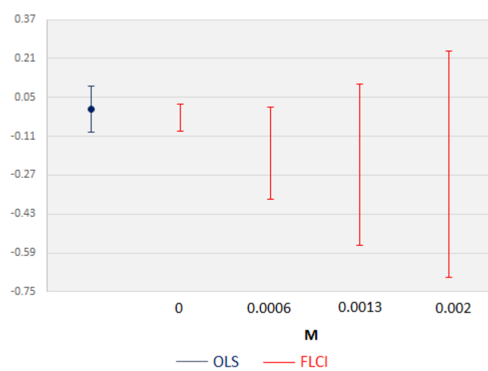
Fall 2016

(b) No restrictions



Nov and Dec 2016

(a) No restrictions



Note: Stars indicate intervals that do not cross zero.

C. Tables

Table A1: Summary statistics for nuclear, hydro and renewable generation

	Pre ETS			Post ETS		
Treated region in WECC	Nuclear generation (MWh)	Hydro generation (MWh)	Renewable generation (MWh)	Nuclear generation (MWh)	Hydro generation (MWh)	Renewables generation (MWh)
CA	2,481.98	2,812.90	2,434.53	1,506.48	1,791.71	4,057.49
	(750.94)	(1,158.53)	(399.23)	(268.66)	(832.48)	(947.48)
NW	625.32	10,328.15	1,512.62	744.68	9,842.57	2,077.80
	(297.12)	(2,882.33)	(346.15)	(196.11)	(2,295.28)	(250.30)
RoW	0	1,956.57	626.24	0	1,608.51	1,133.70
	-	(551.16)	(206.96)	-	(334.96)	(235.16)
SW	2,605.70	516.31	74.28	2,680.31	491.37	276.87
	(375.56)	(136.08)	(44.41)	(334.18)	(115.57)	(70.54)

	Pre ETS			Post ETS		
Control region	Nuclear generation (MWh)	Hydro generation (MWh)	Renewable generation (MWh)	Nuclear generation (MWh)	Hydro generation (MWh)	Renewables generation (MWh)
FRCC	1,936.23	14.96	532.13	2,329.92	18.46	542.05
	(458.51)	(5.04)	(53.65)	(374.68)	(7.32)	(48.46)
MRO-US	8,632.34	842.12	2,931.12	8,283.35	877.07	4,462.99
	(844.34)	(209.71)	(664.13)	(815.15)	(190.70)	(924.96)
SERC	15,952.18	3,105.64	1,431.15	16,461.50	3,277.52	1,952.69
	(1,449.39)	(938.75)	(128.29)	(1,152.76)	(994.19)	(252.13)
SPP	1,399.00	1,229.62	1,310.86	1,442.61	1,124.14	3,009.59
	(448.33)	(280.47)	(421.07)	(442.17)	(304.94)	(696.95)
TRE	3,352.55	54.38	2,100.78	3,313.26	44.61	3,433.54
	(527.21)	(39.29)	(538.64)	(486.36)	(47.37)	(926.75)

Note: Values represent averages between January 2009-December 2012 (Pre ETS) and January 2013-December 2016 (Post ETS). Standard deviations are reported in parentheses.

Table A2: Balancing tests on plant heat rates

	NGCC		Coal	
	Before matching	After matching	Before matching	After matching
Hour 0	-2.161^{**}	-0.889	-0.562	0.199
Hour 1	-2.334^{**}	-1.103	-0.892	-0.407
Hour 2	-2.878^{***}	-1.617	-1.226	-0.590
Hour 3	-2.610^{***}	-1.295	-0.982	-0.686
Hour 4	-2.281^{**}	-0.920	-1.200	-0.996
Hour 5	-1.749^{*}	-0.417	-1.185	-1.263
Hour 6	-2.356^{**}	-0.714	-1.266	-1.322
Hour 7	-2.316^{**}	-0.618	-1.191	-1.305
Hour 8	-2.449^{**}	-0.843	-0.907	-1.180
Hour 9	-1.648	-0.285	-1.046	-0.358
Hour 10	-1.640	-0.159	-0.951	-0.347
Hour 11	-1.987^{**}	-0.559	-0.837	-0.310
Hour 12	-2.194^{**}	-0.804	-0.931	-0.401
Hour 13	-2.481^{**}	-1.220	-0.876	-0.350
Hour 14	-2.293^{**}	-0.936	-0.777	-0.112
Hour 15	-2.245^{**}	-0.843	-0.869	-0.718
Hour 16	-2.188^{**}	-0.822	-0.775	0.062
Hour 17	-2.209^{**}	-0.840	-0.830	-0.722
Hour 18	-2.070^{**}	-0.713	-0.826	-0.948
Hour 19	-1.968^{*}	-0.659	-0.788	-0.610
Hour 20	-1.861^{*}	-0.626	-0.802	-0.754
Hour 21	-0.936	-0.004	-0.817	-0.771
Hour 22	-1.076	-0.369	-0.777	-0.705
Hour 23	-1.292	-0.521	-0.699	-0.718
Morning	-2.180^{**}	-0.594	-1.045	-0.767
Afternoon	-2.381^{**}	-0.985	-0.828	-0.280
Evening	-1.830^{*}	-0.562	-0.815	-0.782
Night	-2.483^{**}	-1.185	-0.969	-0.698

Note: The table reports t statistics of a two-sided test of mean comparisons between treated and control groups before and after matching. *, **, and *** indicate statistical significance at 10%, 5% and 1% level, respectively.

Table A3: Balancing tests on plant age

	NGCC		Coal	
	Before matching	After matching	Before matching	After matching
Age	-2.376^{**}	-1.586	-2.833^{***}	0.642

Note: The table reports t statistics of a two-sided test of mean comparisons between treated and control groups before and after matching. ** and *** indicate statistical significance at 5% and 1% level, respectively.

Table A4: Assumed RPS requirements in 2013 and 2016

	2013	2016
State	RPS	RPS
AZ	4%	6%
CA	20%	25%
CO	12%	20%
MT	10%	15%
NM	10%	15%
NV	18%	20%
OR	5%	15%
WA	3%	9%

Note: California also requires that 50% (65%) of its RPS requirement be met by in-state renewable generation and/or renewable generation in AZ, NV and OR in 2013 (2016).

Table A5: Shares of electricity imports into California, 2013 and 2016

	2013	2016
Imported electricity (TWh)	102.5	100.0
of which:		
(1) specified imports (TWh)	74.9	78.6
share of specified imports over total	*73.1%*	*78.6%*
(2) specified imports from natural gas (TWh)	13.4	13.2
share of specified imports from natural gas over total	*13.1%*	*13.2%*
(3) specified imports from coal and diesel (TWh)	*23.9*	*11.4*
share of specified imports from coal and diesel over total	*23.3%*	*11.4%*
(4) unspecified imports (TWh)	27.6	21.4
share of unspecified imports over total	*26.9%*	*21.4%*

Note: Imports from coal include the line item "MJRP" in the CARB spreadsheet.

References

Hobbs, Benjamin, and Udi Helman. 2004. Complementarity-Based Equilibrium Modeling for Electric Power Markets, in *Modeling Prices in Competitive Electricity Markets* (D. W. Bunn, ed.), 69–97. 2004. John Wiley and Sons.

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