Challenges and Successes in the Energy Transition

NBB Deglobalisation, decarbonisation and digitalisation conference

Mar Reguant

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2024

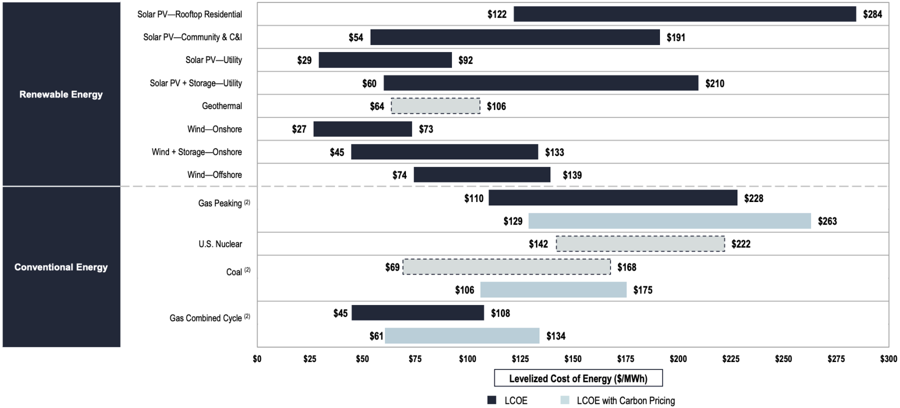
Big push in the electricity sector to decarbonize and electrify

- Need to reduce Green House Gas emissions (GHGs).
- Electricity sector ($\approx$35-40% of CO_2 emissions) has been **most active** and has the greatest potential in making the transition.
- Ambition to move towards **carbon-free electricity** by 2050.
- **Limits to decarbonization**:
  - **Renewables' intermittency** might lead to a potential mismatch between supply and demand, increasing need for flexibility.
  - **Need to improve complementary infrastructure** in high and low voltage.
  - **Vulnerabilities** due to climate shocks.
  - **Growing pressures** due to decarbonization of other sectors (cars, heating, etc.).

Renewables are cost-effective I

Levelized Cost of Energy Comparison—Sensitivity to Carbon Pricing

Carbon pricing is one avenue for policymakers to address carbon emissions; a carbon price range of $40 – $60/Ton[1] of carbon would increase the LCOE for certain conventional generation technologies, as indicated below

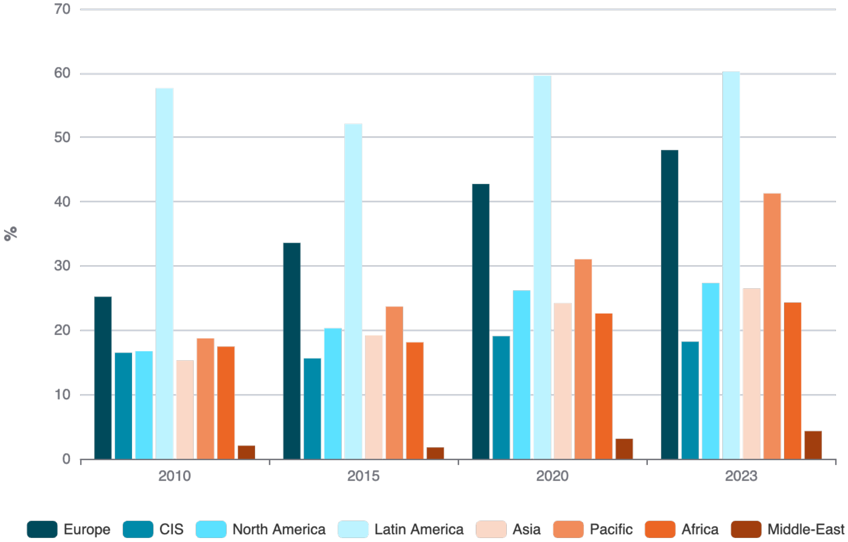


Source: Lazard and Roland Berger estimates and publicly available information.
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the LCOE analysis as presented on the page titled “Levelized Cost of Energy Comparison—Version 17.0”.
(1) In November 2023, the U.S. Environmental Protection Agency proposed a $204/Ton social cost of carbon.
(2) The low and high ranges reflect the LCOE of selected conventional generation technologies including an illustrative carbon price of $40/Ton and $60/Ton, respectively.

Renewables are cost-effective II

Figure 1.7 Competitiveness trends for utility-scale solar PV by country and year, 2010-2022

With growing presence, but far from "net-zero" in most regions



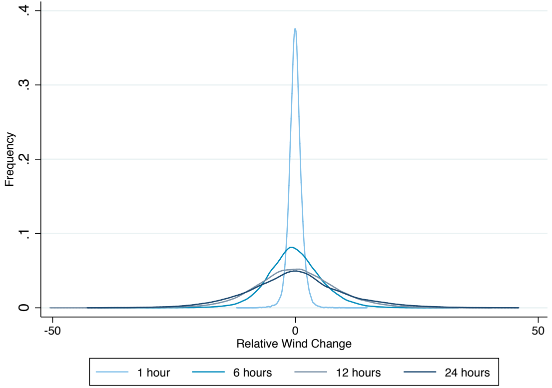
Some challenges remain...

- Several concerns could hinder the advancement of the energy transition:
  - Intermittency and frequency regulation
  - Transmission and reliability
  - Stranded assets and the cost of financing
  - Acceptability and equity, pricing, and job transitions
  - Fiscal pressure even within climate policies: adaptation & mitigation
  - Geopolitical reshaping of trade, e.g., with carbon pricing and new tariffs.
  - Etc.
- I will talk about some of these issue with **examples from my research**.

Challenge 1: Intermittency

Timing

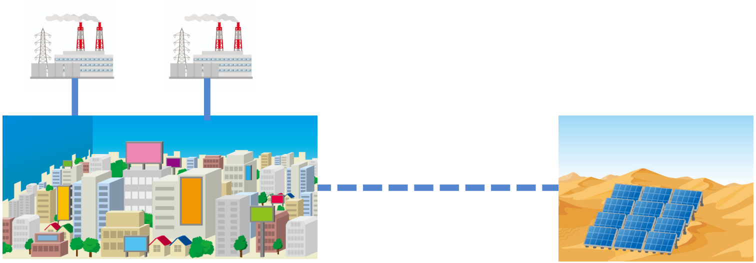
- Wind and solar power cannot be "turned on" based on demand.
- Need to adjust operations to be ready to cover when these sources are not available.
- Wind and solar also reduce the inertia of the system.
- They can increase volatility and uncertainty in the market, harder if markets are absent or underdeveloped.



Challenge 2: Existing networks were not built for renewables

Geography

- Conventional power plants can be placed near demand centers
  - Minimal transmission lines were required to connect supply and demand
- By contrast, renewables are often best generated in remote locations
  - Renewable-abundant regions are not well integrated with demand centers
- Large investment that requires coordination, difficulties in the political economy across regions and countries.



Challenge 3: Stranded assets make the transition harder

Incentives

- Capital costs of renewables is larger, so perceived risks increase its costs in some countries.
- Without proper carbon pricing, natural gas is too cheap (even more in the US).
- Stranded assets in coal and legacy contracts make the transition harder.
- Incumbent incentives to keep the status quo (also for other stranded assets in manufacturing).

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[BLOG] UNION OF CONCERNED SCIENTISTS

Coal Is No Longer a Baseload Resource, So Why Run Plants All Year?

JOSEPH DANIEL, SENIOR ENERGY ANALYST | JANUARY 15, 2020, 12:12 PM EDT

Contents

I. Case study from Spain: Intermittency

II. Case study from Chile: Transmission

III. Case study from the US: Stranded assets

Conclusion

I. Case study from Spain: Intermittency

The Impacts of Wind Power in Spain

- **Question:** What have been the impacts of wind generation in the last decade?
- **Methodology:** Regression analysis of hourly operational data (prices, congestion costs, emissions benefits, etc.).
- **Finding:** Consumers have been better off, even after accounting for the cost of the subsidies. Market design can impact these benefits.
- **Co-authors:** Claire Petersen and Lola Segura-Varo

Several studies explore the benefits

- Cullen (2013) and Novan (2015) measure the emissions reductions benefits from wind production.
- Bushnell and Novan (2021) measure the price impacts of solar in California.
- Abrell, Kosch, & Rausch (2019) assess impacts of wind and solar in Germany and Spain.
- Liski, M., & Vehviläinen (2020) assess impacts of wind in Nordic market.
- Gowrisankaran, Reynolds, & Samano (2016) build a structural model to analyze optimal reliability policies.
- Fell, Kaffine, and Novan (2021) look at environmental impacts of renewables with more transmission
- ...

We focus on the **cost of intermittency** in this paper.

Data

- We get hourly data from the Spanish electricity market (2009-2018). Data from REE and OMIE.
- Data include: market prices, intermittency costs, congestion, and other reliability services, emissions data (tons/CO2), subsidies received (millions), etc.
- We **quantify the impact of wind** on these variables:
  - Benefits: emissions reductions, reduced use of fuels, price reductions for consumers.
  - Costs: increased costs of intermittency (paid by consumers and by wind farms), price reductions for consumers.

Identification strategy

- Given randomness in wind forecasts, we run a regression of the impacts of wind on these variables.
- **Spline approach** to look at the impact at different quintiles:

$$Y_t = \beta_0 + \sum_{q=1}^{5} \beta_q W_{qt} + \gamma X_t + \epsilon_t \ ,$$

  where W_{qt} are spline bins according to the quintiles of the wind variable.
- Examine *average* predicted costs as well as *marginal effects*.

Note on endogeneity

- Wind production can be endogeous due to:
  - Curtailment.
  - Strategic behavior.
- Use forecasted wind either directly or as an instrument to actual production.

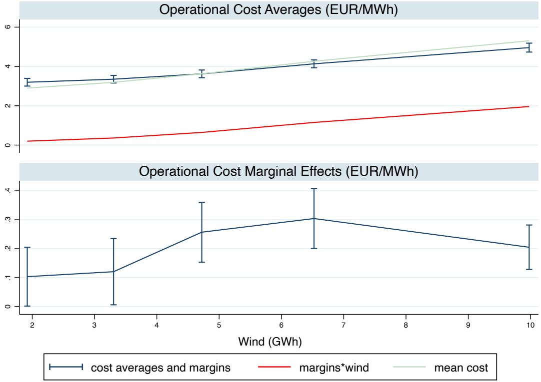
VARIABLES	(1) Wind Forecast	(2) Wind	(3) IV Forecast	(4) IV Power
Forecasted wind (GWh)	0.191			
	(0.0162)			
Final wind production (GWh)		0.152	0.182	0.188
		(0.0140)	(0.0150)	(0.0189)
Observations	83,840	83,841	83,840	81,348
R-squared	0.561	0.557	0.079	0.079

Emphasis on operational costs

- In the literature, often large emphasis on the costs of intermittency from renewable resources.
- Focus on the paper to quantify intermittency costs in the market.
- *Has wind contributed to large increases in operational costs?*
- We identify intermittency costs as the (accounting) costs of providing congestion management, reliability services, balancing, etc.

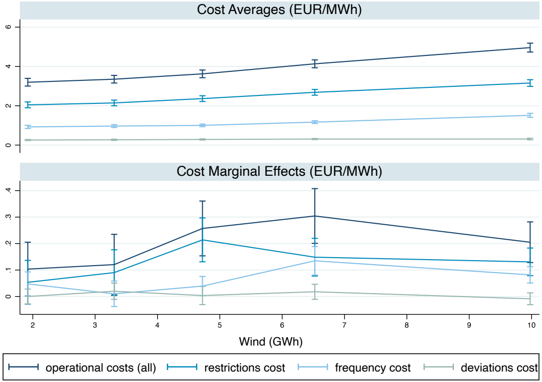
Results for operational costs

- Operational costs go up with more wind.
- However, they don't increase dramatically.
- Marginal effects don't increase.



Decomposition of operational costs

- We quantify effects to different operational services.
- Congestion goes up with wind.



Intermittency and the importance of market design

- There have been discussions on the value of renewables due to their intermittency and the presence of technical constraints.
- The costs of integrating wind power into the electricity market can depend on **how well-designed the market is**.
- Market design also interacts with **subsidies**.
  - E.g., negative prices in Texas or Germany, zero prices in Spain.
- Several markets have adapted their functioning to accommodate renewable power:
  - *California:* EIM market to allow for trade between regions.
  - *Germany:* half-hour markets (instead of hourly).
  - *Europe:* move towards continuous trading to have more flexibility.

Regulation change in 2014...

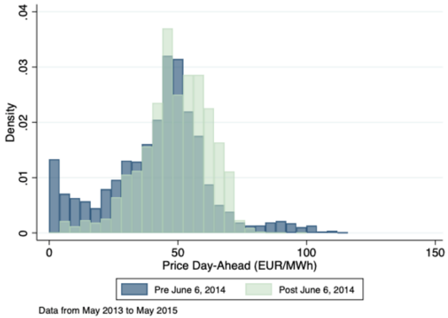
- In 2014, Spain changed how wind power plants are rewarded.
  - Moving away from output-based to capacity-based subsidy.
  - Leaving many plants without support because market price was more attractive.
  - It avoided commonly seen distortions of renewable sources bidding zero (or even negative) to obtain the subsidy.

...has substantial impact on bidding behavior...

- Prices no longer zero.
- We show that wind farms bid zero less often after policy change.
- This increases prices for consumers, increases profits for firms.
- It also avoids unnecessary reshuffling in congestion markets.

Figure 2: Price and wind outcomes before and after the 2014 policy change

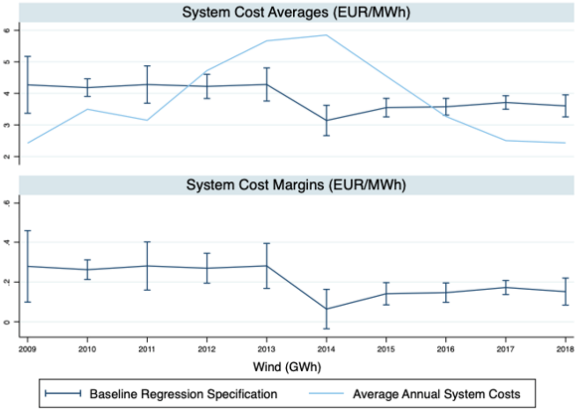
(a) Day-ahead marginal prices before and after policy change



...and leads to a reduction in system cost

- Policy change is also correlated with a reduction in system costs.
- **Disclaimer:** Not causally identified, but suggestive evidence that **market design matters**.

Figure 3: Annual Average and Marginal System Cost Effects



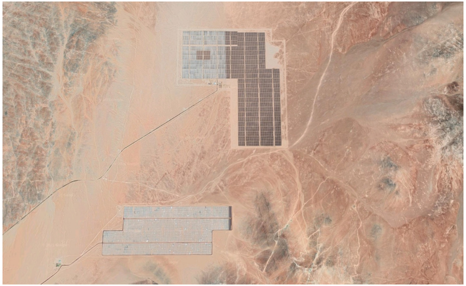
Summary

- Wind investments had a positive impact on welfare for reasonable SCC.
- On average, policy benefited both consumers and producers.
- Details on market design and compensation can substantially impact winners and losers.
- Sometimes perceived as a costly mistake, but a huge early success in climate policy has led to over 20% of generation in Spain being from the wind.
- Regulatory changes can provide useful innovations that reduce costs.

II. Case study from Chile: Transmission

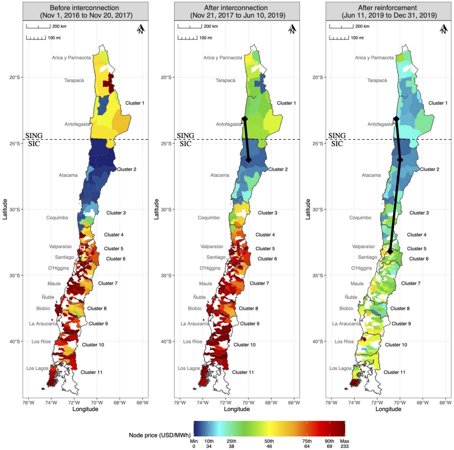
A case study from Chile

- The Chilean context provides a unique case study.
- Chile has large solar resources, but best spots disconnected from demand centers (Antofagasta and Atacama desert).
- Chile successfully connected these areas via ambitious grid projects in 2017 and 2019.
- We provide a *dynamic* quantification of the benefits.

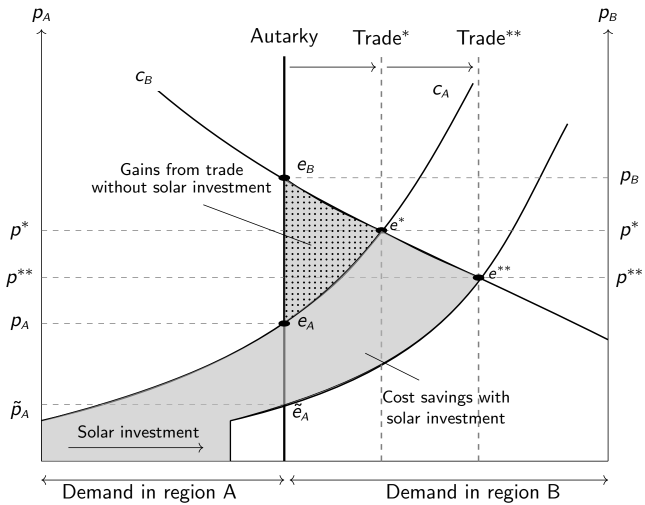


Gonzales, Ito, and Reguant (2023)

- Gonzales, Ito, and Reguant (2022) quantify the value of transmission infrastructure in Chile.
- Question: What is the cost benefit of the expansion project?
- Tools: event study + structural model of the Chilean electricity market.
- Some key findings:
  - We highlight the dynamic benefits of grid expansion, enabling increased renewable expansion.
  - The cost of transmission can be quickly recovered, even when ignoring the added climate change benefits.



Summary of the paper in a picture



Static impacts: Event study effects of the line

$$c_t = \alpha_1 I_t + \alpha_2 R_t + \alpha_3 c_t^* + \alpha_4 X_t + \theta_m + u_t$$

- Our method uses insights from Cicala (2022)
  - c_t is the observed cost
  - c_t^* is the nationwide merit-order cost (least-possible dispatch cost under full trade in Chile)
  - $I_t = 1$ after the interconnection; $R_t = 1$ after the reinforcement
  - X_t is a set of control variables; θ_t is month fixed effects
  - α_1 and α_2 are the impacts of interconnection and reinforcement

Static impacts: Event study effects of the line

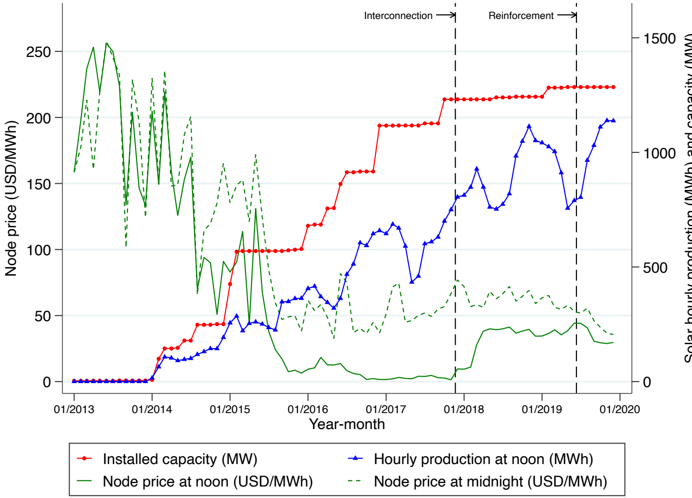
	Hour 12		All hours	
1(After the interconnection)	-2.42	(0.26)	-2.07	(0.17)
1(After the reinforcement)	-0.96	(0.58)	-0.61	(0.37)
Nationwide merit-order cost	1.12	(0.03)	1.03	(0.01)
Coal price [USD/ton]	-0.03	(0.01)	-0.01	(0.01)
Natural gas price [USD/m^3]	-10.36	(4.33)	-0.65	(3.09)
Hydro availability	0.43	(0.14)	0.00	(0.00)
Scheduled demand (GWh)	-0.51	(0.13)	-0.01	(0.00)
Sum of effects	-3.38		-2.68	
Mean of dependent variable	35.44		38.63	
Month FE	Yes		Yes	
Sample size	1033		1033	
R^2	0.94		0.97	

Does this static event study analysis get the full impact?

- Our theory suggested:
  - Yes if solar investment occurs simultaneously with integration
  - No if solar investment occurs in anticipation of integration

Solar investment occurred in anticipation of integration

- Solar investment began after the announcement of integration in 2014
- Plants entered "too early".
  - [→] Static analysis does not capture the full impact of market integration
  - [→] We address this challenge in the next section

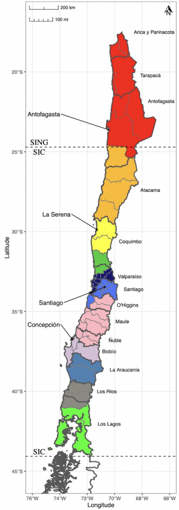


Buidling a model to get at the full effect

- Impacts of the grid can be static and dynamic:
  - Production benefits: more solar can be sent to the demand centers, prices in solar regions go up.
  - Investment benefits: more solar power is built.
- We highlight that an event study is likely to capture only the first kind of effects (e.g., around time of expansion).
- We build a model of the Chilean electricity market to quantify the benefits of market integration including its investment effects.

A structural model to study a dynamic effect on investment

- We divide the Chilean market to five regional markets with interconnections between regions (now expanding to 11)
- Model solves constrained optimization to find optimal dispatch that minimizes generation cost
- Constraints:
  1. Hourly demand = (hourly supply - transmission loss)
  2. Supply function is based on plant-level hourly cost data
  3. Demand is based on node-level hourly demand data
  4. Transmission capacity between regions:
     - Actual transmission capacity in each time period
     - Counterfactual: As if Chile did not integrate markets



We calibrate the model with detailed market data

- Network model
  - k-means clustering of province prices into 5 zones, observed flows between clusters to set transmission.
- Supply curve:
  - based on observed production and/or observed reported costs.
- Demand:
  - based on nodal level data, aggregated to clusters.
- Solar potential:
  - based on days without transmission congestion.
- Cost of solar:
  - based on zero profit condition.

The cost and benefit of the transmission investments

- Cost of the interconnection and reinforcement
  - \$860 million and \$1,000 million (Raby, 2016; Isa-Interchile, 2022)
- Benefit—we focus on three benefit measures
  - Changes in consumer surplus
  - Changes in net solar revenue (= revenue − investment cost)
  - Changes in environmental externalities

Cost-benefit results

Table: Cost-Benefit Analysis of Transmission Investments

	(1)	(2)
Modelling assumptions		
Investment effect due to lack of integration	No	Yes
Benefits from market integration (million USD/year)		
Savings in consumer cost	176.3	287.6
Savings in generation cost	73.4	218.7
Savings from reduced environmental externality	-161.4	249.4
Increase in solar revenue	110.7	183.5
Costs from market integration (million USD)		
Construction cost of transmission lines	1860	1860
Cost of additional solar investment	0	2522
Years to have benefits exceed costs		
With discount rate = 0	14.8	6.1
With discount rate = 5.83%	> 25	7.2
With discount rate = 10%	> 25	8.4
Internal rate of return		
Lifespan of transmission lines = 50 years	6.95%	19.67%
Lifespan of transmission lines = 100 years	7.23%	19.67%

Assessing the cost-benefit

- With the model, we can compute the benefits of the line, with and without investment effects.
- We find that investment effects are key to justify the cost of the line.
- The line was also very attractive from a consumer welfare perspective, even at 5.83% discount rate (Chile's official rate).
- Political economy makes renewable expansion "easy" in Chile.
- How to reduce political economy challenges in other jurisdictions?

III. Case study from the US: Stranded assets

Retirement of Coal Capacity by Regulatory Status in the US

- Coal exited more quickly in restructured states than in regulated ones.

Source: Authors' calculations from EIA data.

Gowrisankaran, Langer, and Reguant (2023)

- Gowrisankaran, Langer, and Reguant (2022) quantify the delay in phase-out of coal due to regulatory distortions.
- Question: What is the impact of regulatory structure in delaying stranded asset exit?
- Tools: descriptive evidence + structural model of regulation.
- Some key findings:
  - We highlight that incentives to use existing capital even if its marginal cost does not make it profitable.
  - Focus on coal-to-gas US transition, but relevant to the gas-to-renewable phase.

Overview of Model

- We model the regulator as having two instruments to create appropriate incentives:
  1. Offered maximum rate of return declines in utility's total variable costs, TVC.
  2. Extent to which coal enters the rate base depends on it being used and useful.
- Utility optimizes against the regulatory structure:
  - Long run: chooses coal retirement and combined-cycle natural gas investment.
  - Each hour: chooses generation mix and imports to meet load.
- Utility faces two conflicting incentives:
  1. Invests in and operates low-cost technologies to increase its rate of return.
  2. May use expensive coal generators to ensure that they are used and useful.

Empirical Approach

- Our model relies on both regulatory and cost parameters, including:
  - How much high *TVC* decreases the allowable rate of return.
  - How much usage increases coal's contribution to the rate base.
  - Operations and maintenance, ramping, and investment/retirement costs.
- Estimate regulatory and operations parameters with a nested fixed-point indirect inference approach that seeks to match important data correlations.
  - Find parameters that match key correlations in simulated model to data.
- Estimate investment/retirement costs with a GMM nested fixed-point approach.
  - Follow Gowrisankaran and Schmidt-Dengler (2024) algorithm that facilitates computation of models with many choices.

The Energy Transition Helps Identify the Model

- Consider a utility in 2006 with mostly coal capacity, but facing low-cost CCNG.
- Utility faces conflicting incentives:
  - If it invests in and uses CCNG, total variable costs fall and hence profits rise.
  - However, this reduces the usage rate of coal capacity.
  - Makes it harder to justify coal maintenance or upgrade expenditures as prudent.
- This tension will potentially lead the utility to keep and over-use legacy coal capacity.

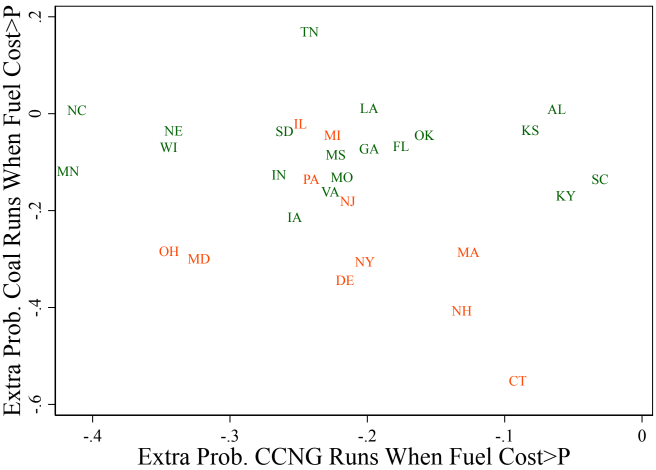
- Contrast this with a utility with higher CCNG capacity before the energy transition.
  - Relative investment in and usage of CCNG identifies regulatory parameters.

Empirical Support for Our Regulatory Model

We investigate correlations in the data that underlie our model:

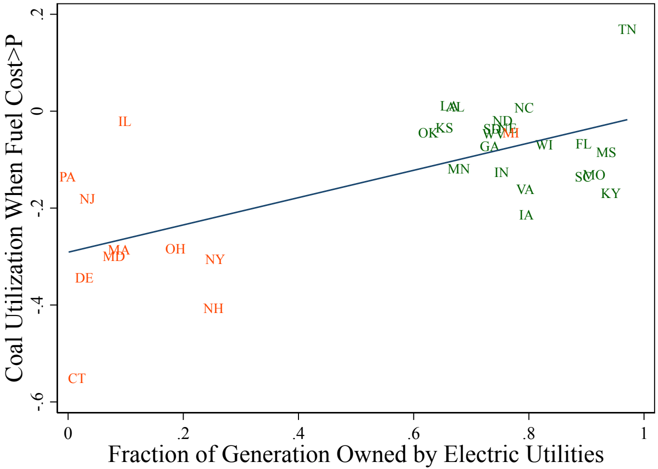
1. Relationship between observed rates of return and total variable costs.
2. Propensity for coal generators in regulated markets to run "out of dispatch order" relative to restructured markets.

Out-of-Dispatch Order Generation Varies Across States



- Most restructured states behave differently than regulated with coal but not CCNG.

Out-of-Dispatch-Order Generation vs. Utility Ownership Share



- All regulated states have high utility ownership.
- Coal's responsiveness to low wholesale prices correlates strongly with utility ownership share.

Northwestern

Overview of Structural Estimation

1. Estimate import supply curves following Bushnell, Mansur, and Saravia (2008).
   - Allow intercept and slope to depend on natural gas fuel price.
2. Estimate most structural parameters from utilities' hourly generation decisions by fuel/technology type.
   - O&M and ramping cost parameters.
   - Response of maximum rate of return to total variable costs.
   - Parameters governing how much coal capacity contributes to effective capital.
3. Estimate investment/retirement costs from dynamic decisions.
   - Take as an input the annual profits in each state.
   - Estimate the operations model and simulate profits across a grid of time-varying states.

Coefficient Estimates for Operations Model

Parameter	Notation	Estimate	Std. Error
Penalty for High TVC_t	γ	0.429	(0.08)
Rate Base per MW of Effective Capital (Millions \$)	α	0.221	(0.06)
Coal Capacity Contribution to Effective Capital	α^{COAL}	1.117	(0.51)
Coal Usage Logit Base	μ_1	-0.589	(0.11)
Coal Usage Logit Slope	μ_2	5.641	(0.87)
NGT Contribution to Effective Capital	α^{NGT}	2.134	(1.00)
Ramping Cost for Coal (100\$ / MW)	ρ^{COAL}	0.578	(0.11)
Ramping Cost for CCNG (100\$ / MW)	ρ^{CCNG}	0.219	(0.31)
O&M Cost for Coal (\$ / MWh)	om^{COAL}	16.350	(3.92)
O&M Cost for CCNG (\$ / MWh)	om^{CCNG}	2.594	(0.10)
O&M Cost for NGT (\$ / MWh)	om^{NGT}	19.767	(14.40)

Coefficient Estimates for Investment/Retirement Decisions

Parameter	Notation	Value	Std. Dev.
Fixed cost of coal retirement × 1e2	δ_0^{COAL}	-0.446	(9.79)
Linear coal cost per MW	δ_1^{COAL}	3.196	(0.44)
Quadratic coal cost per MW / 1e3	δ_2^{COAL}	0.117	(0.02)
Coal shock standard deviation per MW	σ^{COAL}	-0.430	(0.02)
Fixed cost of CCNG investment × 1e2	δ_0^{CCNG}	-0.509	(0.01)
Linear CCNG cost per MW	δ_1^{CCNG}	6.487	(0.08)
Quadratic CCNG cost per MW / 1e3	δ_2^{CCNG}	0.270	(0.05)
CCNG shock standard deviation per MW	σ^{CCNG}	-1.671	(0.06)

Note: All values in millions of 2006 dollars.

Findings

- Current regulatory structure creates unintended incentives to use more coal:
  - Cost minimizer virtually eliminates coal capacity in the 30 years after natural gas prices fell, while social planner essentially stops *using* coal immediately.
  - Current RoR regulation retires only 45% of coal capacity over this horizon.
  - Marginal adjustments to RoR regulation don't approach cost minimization.
  - RoR with CO_2 tax has 90% short-run pass through, but similar long-run effect.
- Broader takeaways:
  - Over-investment in CCNG may affect the transition to renewables above and beyond short-run marginal incentives.

Conclusion

Evaluating the energy transition

- The energy transition provides a unique opportunity to decarbonize electricity generation.
- I evaluated the impacts and challenges of the transition using a diverse set of tools.
- Challenges and concerns remain, lots of areas for economic research.

- **More details?**
  - Measuring the Impact of Wind Power and Intermittency, with Claire Petersen and Lola Segura, *Energy Economics*.
  - The Investment Effects of Market Integration: Evidence from Renewable Energy Expansion in Chile, with Luis Gonzales and Koichiro Ito, *Econometrica*, 91(5): 1659-1693, 2023.
  - Energy Transitions in Regulated Markets, with Gautam Gowrisankaran and Ashley Langer, revise & resubmit at *AER*.