How Empirical Economic Analysis Can Contribute to the Energy Transition

Frank A. Wolak

Director, Program on Energy and Sustainable Development (PESD)
Holbrook Working Professor of Commodity Price Studies
Department of Economics
Stanford University
wolak@zia.stanford.edu

Note: All papers cited are at http://web.stanford.edu/group/fwolak

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Motivation

- Many jurisdictions are attempting to reduce the carbon content of electricity supply
  - Intermittent renewable resources–wind and solar–are expected to play a major role
- Large shares of intermittent renewable resources significantly increase challenge faced by wholesale market operators
  - Texas in February 2021 and July 2022
  - California August 2022
- Distributed renewables–primarily rooftop solar–compete with grid-supplied electricity
  - Inefficient pricing of retail electricity has large costs

Electricity Market Design I

- Typical market design process not possible for electricity because of single grid and high level of reliability of supply demanded
- Consumer vote with their feet in typical market design process
  - Coffee market–Starbucks, Peets, Philz (in Silicon Valley)
- Electricity market design takes place through regulatory process guided by stakeholder input at Federal and State level in United States
- How electricity market is designed can have an enormous impact on market outcomes
  - Poor market designs can cost consumers billions of dollars annually

Electricity Market Design II

- Major wholesale electricity market design challenge–Market Power
- Wholesale electricity has all features that make exercise unilateral market power very profitable
    - Production subject to extreme capacity constraints
    - Supply must equal demand at every instant in time
    - Product is very expensive to store
    - Delivery must take place through a specialized transmission network
    - How product is priced to final consumers makes real-time demand close to perfectly price inelastic
- Limiting exercise unilateral market power in wholesale electricity markets has been extremely challenging
    - Many examples–United Kingdom, California, New Zealand Market, Colombia, Australia, etc.

How Combining Economic Theory and Econometric Analysis Aid in Energy Transition

- **Economics Incentives faced by market participants drive market outcomes in vertically-integrated monopoly regime and wholesale market regime**
  - When market rules change, incentives faced by market participants change, which causes their behavior to change
  - Technology is the same in both regimes, but how it is used changes because market participants face different economic incentives
  - Market design is choice between **imperfect competition** and **imperfect regulation**–For more this point see Wolak (2015)"Regulating Competition in Wholesale Electricity Supply"
- **Role of Economists:** Devise market rules that make it in unilateral interest of all participants to achieve policymaker's objective
- **Proposed Market Design Objective:** Electricity consumers benefit from transition to wholesale market regime
  - Lower average retail prices consistent with long-term financial viability of industry and achieving region's environmental policy goals

Five Areas Where Empirical Economic Analysis Can Contribute

- Match Between Market Mechanism that Sets Prices and Generation Unit Output Levels and Physics Governing Operation of Grid
  - The INC/DEC game in zonal markets and the benefits of multisettlement Locational Marginal Pricing (LMP) markets
- Optimal Transmission Network Configuration Depends Market Structure
  - Transmission upgrades improve performance of imperfectly regulated vertically-integrated monopoly or imperfectly competitive wholesale market
- Long-Term Resource Adequacy with Significant Intermittent Renewables
  - Origin of *Reliability Externality* in the wholesale market regime and how to internalize it
- Efficient Network Pricing with Distributed Generation
  - Inefficient network pricing leads to inefficient bypass of grid-supplied electricity
- Distributed versus Grid Scale Intermittent Renewables
  - Distributed intermittent renewables investments avoids, little if any, need for future investments in distribution grid

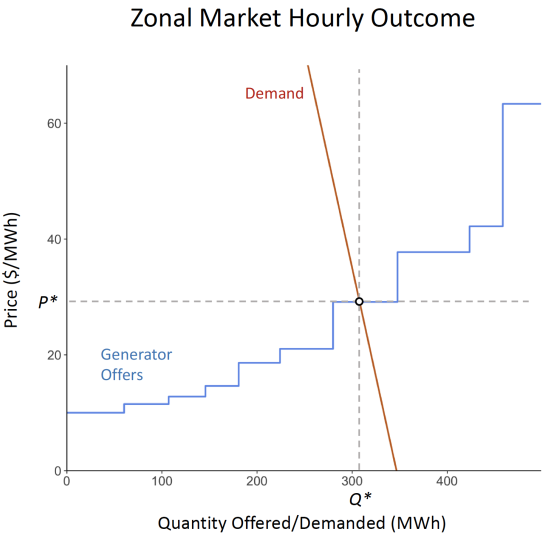
Market Model versus Physics of Grid Operation

- Initial wholesale markets ignored physics of grid operation
  - Single-price or zonal-pricing financial markets to settle day-ahead and intra-day transactions, while secure system operation could be left to engineering models and real-time re-dispatch instructions
- Designers argued that transmission congestion would be infrequent and costs associated with real-time re-dispatch would be small
- However, once simplified markets were implemented, costs of re-dispatch rapidly became much higher than expected
- Experience from all simplified day-ahead markets showed that in "real-time physics wins"
- All generation unit owners understand this and use this knowledge to earn additional profits

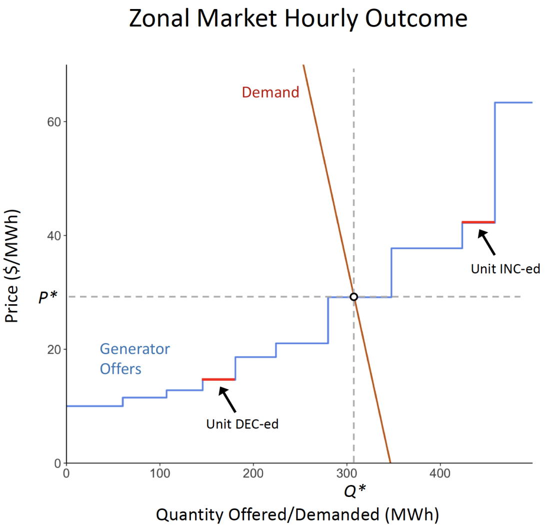
INCs and DECs in Simplified Market Design

- Infinite network capacity is implicitly assumed in simplified market, as well as absence of system security constraints, generation unit ramping constraints, and costs associated with generation unit starts and stops
- All generators and loads in the region settle at same price in simplified market
- After simplified market settlement, a real-time re-dispatch process takes place to ensure the dispatch is physically feasible
- Because of real-time operating constraints certain generation units are given instructions to provide incremental energy (INC-ed) or to buy back decremental energy (DEC-ed) to resolve constraints
    - Paid as offered for INCs and purchase as bid for DECs
- Cost of redispatched INCs and DECs paid by consumers

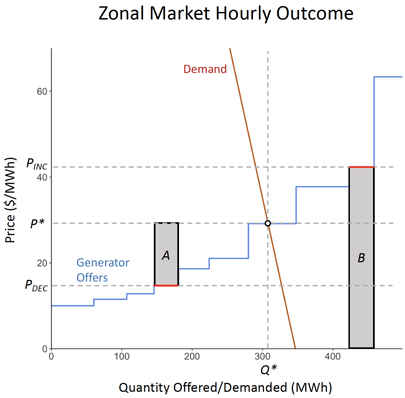
Simplified Market Settlement



Simplified Market Infeasibilty



Simplified Market in Real-Time



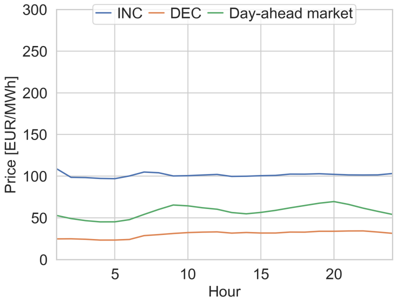
- The generator that was DEC-ed earns $P^* - P_{DEC}$ times the amount of decremental energy (Box A)
- The generator that was INC-ed receives P_{INC} times the amount of incremental energy less marginal cost (Box B - marginal cost)
- Generators that have a high probability of being DEC-ed then have an incentive to bid lower to maximize profit
- Generators that have a high probability of being INC-ed have an incentive to bid higher

The "INC/DEC" Game

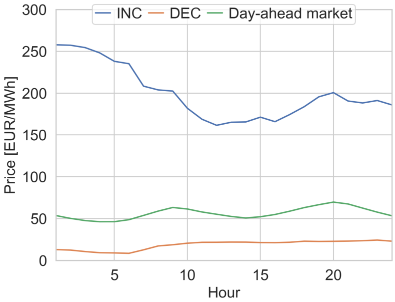
- Rapid growth in re-dispatch costs in simplified markets in United States due in large part to these incentives
    - Commonly referred to as the "INC/DEC Game"
- All European markets–United Kingdom, Italy, Germany, the Netherlands, and Spain have simplified market with redispatch process
    - Increase in intermittent renewables significantly increases uncertainty in patterns of transmission congestion and number of operating constraints
    - Re-dispatch costs increasing rapidly in all European markets driven in part by increasing share of intermittent renewables
- Empirical analysis of frequency and cost of INC/DEC game in Italian market
    - Graf, Quaglia, and Wolak (2021) "Simplified Electricity Market Models with Significant Intermittent Renewable Capacity: Evidence from Italy" on web-site

Incentives to Buy/Sell in Italian Re-Dispatch Market

North Bidding Zone



Center-South Zone



Key Takeaway

Price received [paid] for INCremental [DECremental] energy above [below] the day-ahead market price

Motivation for Empirical Strategy

- A rich set of constraints (e.g., transmission, voltage, frequency, reserves) necessary for a *secure* real-time operation of the grid. These are not accounted for in simplified market
- Market participants are aware of these physical constraints and have incentive to earn higher price from INC in re-dispatch market or buy back energy sold at day-ahead price at offer price as a DEC in re-dispatch market
- **Caveat:** Market participants must be able to *predict* if and when these constraints will be binding in order to from profit INCs and DECs in re-dispatch market

Empirical Analysis—Step 1

Estimate generation unit-level models of hourly probability of INC or DEC in re-dispatch market

- Use hourly unit-level offer curves for the day-ahead market and real-time re-dispatch market between 2017 and 2018
- Select most important combined cycle gas turbine units (provided by Italian Grid Operator) that are used to for re-dispatching
- Estimate random forest model for probability that a unit will be INCed/DECed using forecasts of system conditions known before the day-ahead market closes
  - National zonal day-ahead forecasts for demand and renewables
  - Neighboring countries' (+ Germany) day-ahead forecasts for demand and renewables
  - Day-ahead market cross-border transmission limits with adjacent countries and the national zonal transmission limits
  - Month-of-year, hour-of-day, and workday indicator variables

Empirical Analysis—Step 2

Calculating day-ahead offer markups (P(offer) - MC)

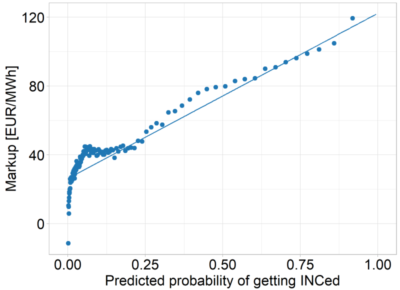
- Defined as the day-ahead market offer-price minus short-run marginal cost estimate
- Unit-level short-run marginal cost estimates are based on heat-rates estimates, fuel-cost, environmental cost such as CO_2 emissions allowances, and variable operations and maintenance cost
- Use offer-quantity weighted average offer-price to have a single day-ahead market offer price number for each unit and hour
- For each unit and hour of the sample match day-ahead market offer markup to predicted probability of that unit getting INCed or DECed in the real-time re-dispatch market

Graphical Results

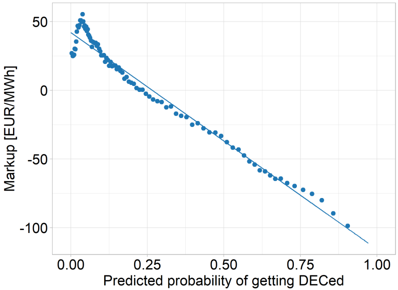
Binscatter of unit-level day-ahead offer markup and unit-level estimated probability of getting INCed/DECed

Note: Control for unit, hour-of-day, day-of-week, month-of-year fixed effects using nonparametric binscatter

INC



DEC



Empirical Results

- A 0.1 increase in probability of being INC-ed predicts €5/MWh increase in day-ahead offer price
- A 0.1 increase in probability of being DEC-ed predicts €6/MWh decrease in day-ahead offer price
- Average day ahead market price was €61.3/MWh during sample period
- Total re-dispatch costsl estimated to be approximately 10% of total day-ahead wholesale energy costs for sample period
    - Italian market likely have lowest re-dispatch costs of all European markets because it has multiple pricing zones, not just one for country

Solution: Price All Relevant Operating Constraints

- Generators submit start-up and minimum load costs and energy offer curve along with ramp rates
- Market model accounts for transmission network configuration, ramp rates of generation units, capacity constraints of units, minimum operating level, voltage constraints
  - Thousands of operating constraints modeled in day-ahead and real-time market
- These markets are called multi-settlement Locational Marginal Price (LMP) markets
- LMP is the change in the optimized as-offered cost of serving an additional unit of load (MWh) at the associated electrical node in the corresponding settlement interval
  - Day-ahead market simultaneously solves for day-ahead market outcomes for all 24 hours of following day
- By approximating power flow through a system of linear equations, locational marginal pricing reflects the underlying physical and security constraints of the electrical system in market mechanism

Benefits of a Nodal Market Model

- Physically infeasible schedules unlikely to emerge from the day ahead solution because relevant real-time operating constraints modeled in market
- Moreover, generators have incentive to operate as they have cleared in the day ahead
  - Generators that under supply in real-time will have to buy the difference at real-time prices
  - Generators that over supply in real-time will get paid real-time prices
- **Key Economic Insight:** Make match between market *model* used to set prices and dispatch levels as close as possible to how actual network operates
  - Balance this goal against computational complexity of solving mixed integer programming problem used to obtain schedules and LMPs
- Match is never perfect, but it is a moving target
  - All US LMP markets assume a Direct Current (DC) power flow when reality is Alternating Current (AC)
  - As more intermittent renewables are added to region more operating constraints must respected in system operation

Restructured Markets and Nodal Market Design

- There are now seven LMP markets in the United States: CAISO, MISO, ISO-NE, NYISO, PJM, SPP, and ERCOT, but only MISO, NYISO and SPP started that way
- Significant market efficiency benefits to transitioning from simplified day-ahead market to multisettlement LMP market
  - Wolak (2011) "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets," finds a 2.1% reduction in variable costs and 2.5% decrease in heat input for same total generation as a result of nodal market implementation for estimated total annual operating cost savings of approximately $100 million
  - Triolo and and Wolak (2022) "Quantifying the Benefits of Nodal Market Design in the Texas Electricity Market," finds daily costs savings for same generation level of 4 percent for annual estimated cost savings of approximately $300 million
- Many simplified markets outside of the US are struggling with high level of re-dispatch costs due in large part to a growing share of intermittent renewables

The Economics of Transmission Expansions

- Transmission network improves performance of imperfectly regulated vertically-integrated monopoly
  - Transmission expansions increase ability of vertically integrated utility to substitute *high cost* supply near load center with *low cost* supply from distant resources
- Transmission network improves performance of imperfectly competitive wholesale market
  - Transmission expansions in wholesale market regime increases number of firms able to compete to supply electricity at each location in transmission network
  - Increases amount of *low-priced* energy that can displace *high-priced* energy at load centers
- **Conclusion:** Optimal transmission network configuration different for vertically-integrated regime versus wholesale market regime
  - Least-delivered cost-to-consumers transmission network is not the same under both regime because expansions improve imperfectly regulatory process or imperfectly competitive wholesale market

The Economics of Transmission Expansions

- Transmission planning is optimal second-best problem that is regime specific
  - Transmission network configuration impacts ability of supplier to exercise unilateral market power
  - Suppliers have economic incentive to take transmission network configuration into account in formulating offer curves
  - For more on this point see Graf and Wolak (2021) "Measuring the Ability to Exercise Unilateral Market Power in Locational-Pricing Markets: An Application to the Italian Electricity Market"
- Additional transmission capacity can increase number of hours per year that supplier faces competition from more suppliers in market
  - Causes more competitive behavior by supplier (submit offer curve closer to marginal cost curve)
- For more details on this mechanism see Wolak (2021) "Transmission Planning and Operation in the Wholesale Market Regime"

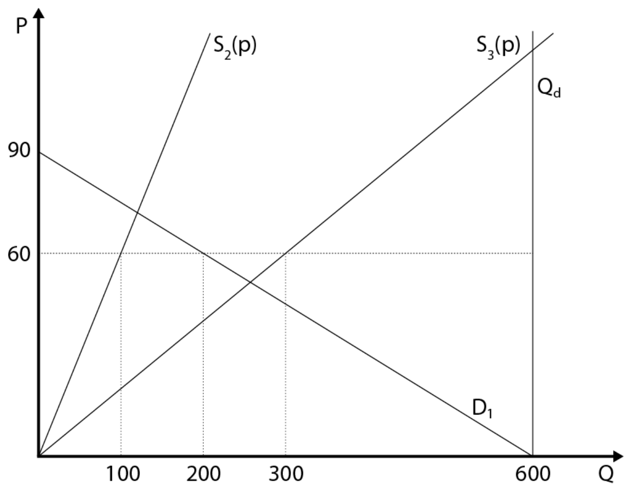
How Do Firms Exercise Unilateral Market Power

An unilateral profit-maximizing supplier acts as a monopolist against *residual demand* curve left by competitors

- Cournot competitor faces residual demand equal to market demand less output choice of all competitor
- Bertrand competitor faces residual demand equal to market demand below price of competitor and zero above this price
- Suppliers in wholesale electricity market submit non-decreasing willingness to supply functions, $S(p)$
- $DR(p) = D(p) - SO(p)$, market demand $D(p)$ less aggregate willingness to supply of all other firms, $SO(p)$
- Supplier submits offer curve, $S(p)$ to achieve p that attempts to maximize ex post variable profit, $\pi(p) = DR(p)(p - c)$ where c marginal cost of production
    - For more on this point see Wolak (2000) "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market"

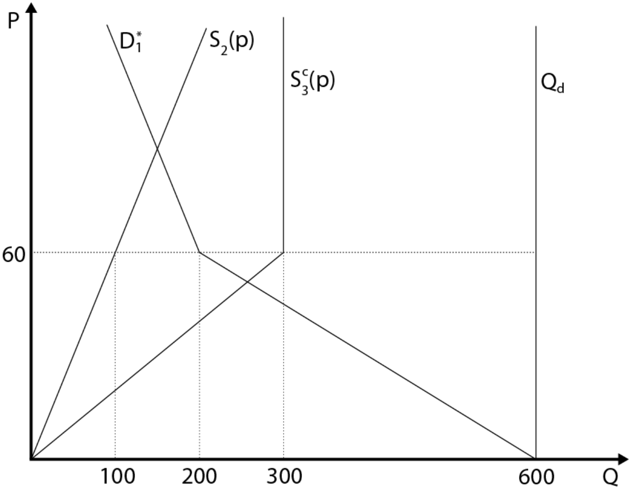
Residual Demand without Transmission Constraint

Construction of Residual Demand Curve of Firm 1



Residual Demand with Transmission Constraint

Feasible Residual Demand of Firm 1 with Transmission Constraints



Measuring Competitiveness of Transmission Investment

- Change in wholesale purchase costs to electricity consumers associated with transmission expansions (due to more competitive offer behavior by suppliers)
  - If wholesale energy cost savings to consumers is more than cost of network expansion consumers should be willing to pay for it
  - Wolak (2014) "Measuring the competitiveness benefits of a transmission investment policy: The case of the Alberta electricity market," finds many transmission upgrades in Alberta can be justified based on competitiveness benefits
  - Awad et. al (2010) "Using Market Simulations for Economic Assessment of Transmission Upgrades: Application of the California ISO Approach," demonstrates that competitiveness benefits are a major source of consumer benefits for a proposed transmission upgrade in California
- Many regions recognize existence of competitiveness benefits from transmission expansions, but limited progress has been made in rigorously including them in planning process
- Growing share of intermittent renewables implies competitiveness benefits of many transmission expansions likely to become even larger

Long-Term Resource Adequacy Mechanism

- In vertically-integrated geographic monopoly regime, utility is responsible for ensuring that demand is met under all possible future system conditions
    - Regulator penalizes monopoly for supply shortfalls
- In wholesale market regime no single entity is responsible for ensuring system demand is met under all possible system conditions
    - Independent System Operator (ISO) can only operate market with resources offered into market
    - Generation unit owners can only supply energy from the generation units they control
    - Retailers can only purchase the energy that generation unit owners supply to wholesale market
- Conclusion—Unless regulator treats electricity like any other product (see next slide), wholesale market regime requires a long-term resource adequacy mechanism

Electricity is Different From Other Products

- Regulatory bargain in vertically-integrated monopoly regime
  - If monopoly is willing to supply all consumers at price set by regulator, then regulator agrees to set that price to allow monopoly an opportunity to recover all prudently incurred costs plus a return to capital invested
- Reliability externality arises in wholesale market regime because regulator is unwilling to commit to using real-time price of energy to clear market under all possible future system conditions
  - Lack of interval meters often used to justify this unwillingness of regulator "to treat electricity like any other product
  - Events in Texas in February 2021 demonstrate likely reasons why regulators are unwilling to treat electricity like any other product
  - See Wolak (2022) "Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables"

Reliablity Externality in Wholesale Market Regime

- **All consumers know that random curtailment will occur if aggregate supply is less than aggregate demand**
  - This implies that no customer faces full expected cost of failing to procure adequate energy in forward market
  - Cannot curtail specific customers during rolling blackouts, only all customers in a specific region of grid
- **Conclusion: Because of existence of "reliability externality" in markets with finite offer cap, regulator must mandate a long-term resource adequacy mechanism**
  - Ensure adequate supply of *energy* to meet system demand under all possible future system conditions and allowed short-term wholesale prices
- Because of the increasing share of intermittent renewables in many electricity markets energy shortfalls can occur despite installed generation capacity much larger than annual system demand peak
  - Not surprising that energy supply shortfalls occurred in Texas (February 2021) and California (August 2020) where annual shares of intermittent renewable energy are by far the largest in US

Historical Approach to Long-Term Resource Adequacy

- Industry with dispatchable (typically, thermal) resources, mechanical meters, and offer cap on short-term market
- Major concern is sufficient installed capacity to meet system demand peak
- Assign all retailers firm capacity obligations equal to multiple of annual peak demand
  - Between 110 and 120 percent of peak demand, depending on region
- Firm capacity is the amount of **energy** generation unit can produce under stressed system conditions
  - For thermal resource this is typically equal to nameplate capacity times the availability factor of unit
  - Availability factor is percent of hours of the year unit is available to produce energy

What is Firm Capacity of an Intermittent Resource?

- Firm capacity of hydroelectric resources is typically based on historical worst hydrological conditions, but this does not always prevent energy supply shortfalls
  - For example from Colombia, see McRae and Wolak (2016) “Diagnosing the Causes of the Recent El Nino Event and Recommendations”
- For wind and solar resources, it is extremely difficult to determine firm capacity
  - Firm capacity of a MW of wind or solar capacity declines with share of wind or solar energy in system demand because of high degree of contemporaneous correlation in output across locations
  - For example from California, see “Wolak (2016) “Level versus Variability Trade-offs in Wind and Solar Generation Investments: The Case of California”
- Assignment of firm capacity to intermittent wind and solar resources involves significant ”engineering alchemy”
  - If stressed system conditions occur when it is dark or when there is no wind, then firm capacity of solar and wind unit should be zero
  - Supply shortfalls in August 2020 in California and February 2021 in Texas are cases for this point

Reliability of Firm Capacity of Thermal Resource

- Firm capacity construct with thermal resource based on assumption that availability of individual thermal resources are independent random events
    - Suppose region has peak demand of 1,000 MW and market composed of equal size thermal units with availability factor of 0.9 and outages are independent across units
    - With 100 MW units, then each unit has firm capacity of 90 MW and a 1.17 times peak demand requirement ensures system peak is met with 0.96 probability with 13 units
    - With 20 MW units, then each unit has firm capacity of 18 MW and 1.17 times peak demand requirement ensures system demand peak is met with 0.999 probability with 65 units
- Key assumption for this reliability outcome with thermal resources is independence of availability of individual generation units
- This is a terrible assumption for intermittent hydro, wind and solar resources that have extremely high degree of contemporaneous correlation across units

Firm Capacity and Import Dependent Regions

- Capacity-based approaches poorly suited to import-dependent regions
- Generation source of an electricity import to a region is a financial construct
  - Two connected bathtubs view of electricity imports–If more electricity poured into tub A than is draining from tub and less electricity is poured into tub B than is draining from tub, electricity flows from tub A to B
  - Impossible to know which generation unit in region A is producing energy flowing into region B
- **Conclusion:** Capacity-based construct for long-term resource adequacy poorly to intermittent renewables and import-dependent regions
  - Note that because renewables must be produced where water, wind or solar resource exists, import share in most regions likely to increase

Standardized Energy Contracts for Resource Adequacy

- Energy-only market versus capacity market is false dichotomy
  - A long-term resource adequancy mechanism is necessary in any electricity market with finite offer cap because of reliability externality
  - As experience of Texas in February 2022 demonstrates, higher offer cap on short-term market reduces probability of supply shortfall but increases its realized cost
- **Important Fact: There has never been a supply shortfall caused by inadequate generation capacity**
  - All supply shortfalls in California, Texas, New Zealand, Colombia, Brazil, etc., caused by inadequate energy
- Standardized Fixed-Price Forward Contracts (SFPFC) approach to Long-Term Resource Adequacy
  - Wolak (2021) "Market Design in a Intermittent Renewable Future: Cost Recovery with Zero Marginal Cost Resources"
  - "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California, Submission to Track 3B.2 Proceedings R.19-11-009 at California Public Utilities Commission," on web-site

The Cost of Inefficient Network Pricing

- Historically network costs recovered through a cents per kilowatt-hour (KWh) charge to final consumer
  - Did not lead to inefficient decision to consume electricity (not the amount consumed), because household had no alternative to grid-supplied electricity
- Distributed (rooftop) solar provides household with ability to avoid purchases from grid
  - Pay cents/KWh charge only for electricity withdrawn from grid
  - Retail price is avoided cost of energy from solar panels
  - P(retail) = P(Energy) + P(Trans+Dist) + P(Other)
  - Other = retailing margin and fixed cost of state policies
  - State policies include energy efficiency, renewables, storage, and low income consumers programs
- Marginal cost of grid supplied electricity is P(Energy) + Distribution Losses, which are less than 10% of P(Energy) in industrialized countries

Distribution Network Cost Increases–The Denominator

- Fixed cost of distribution grid does not depend on how many kWh are withdrawn from grid
  - Very small marginal cost of delivering 1 KWh (primarily losses)
- As more customers install distributed (rooftop) solar, the same fixed cost must recovered from fewer total KWh which implies an increase in cents/KWh charge
- Higher cents/KWh charge increases incentive to install distributed solar
  - Consumer avoids paying higher distribution charge
- More spending on “Other” factors also increases per unit retail price

Distribution Network Cost Increases–The Numerator

- As more distributed solar is installed in a given distribution grid, upgrades may be necesary
  - Manage large surges of energy injections to grid (even power flows back to transmission network) during periods of day with significant solar energy
  - Solar system sized to produce close to customer's monthly consumption produces more electricity than customer durimg consumes daylight hours
  - Annual capacity factor of rooftop solar system in California is approximately 15 percent
  - Annual capacity factor is total energy produced annually divided by nameplate capacity times number of hours in the year
- Grid upgrades to accommodate solar increases fixed cost of grid, which further increases cents/KWh charge

Inefficient Network Pricing Leads to Inefficient Bypass

- Current average residential price in California is approximately 23 cents/KWh
  - All three investor-owned utilities employ increasing block prices that can be as high as 40 cents/KWh
- At $3.00/Watt installed, rooftop solar photovoltaic (PV) system has a levelized cost of energy equal to 15 cents/KWH (3 percent real discount rate)
  - Levelized cost equals discounted present value of lifetime costs divided by discounted present value of lifetime energy production
  - Going solar requires no subsidies to be privately profitable for "typical" California household
- Average annual wholesale cost of energy and ancillary services in 2021 was about 4 cents/KWh
  - **Conclusion:** Socially unprofitable to invest in rooftop solar, because it is much cheaper for customer to consume electricity from wholesale market

Inefficient Bypass of Grid Supplied Electricity

Divergence between privately optimal decision for household and socially optimal decision due to inefficient distribution network pricing

- Economically inefficient bypass of grid-supplied electricity
- Household willingly substitutes 15 cents/KWh electricity for 4 cents/KWh electricity because this avoids 19 cents/KWh = (23 cents/KWh - 4 cents/KWh) charge for network and "Other" *fixed costs*

In California and most other US jurisdictions, marginal incentive to install rooftop solar even larger for high consumption households because of increasing block retail prices

- Replace 40 cents/KWh electricity with 15 cents/KWh rooftop solar energy

Two Policy Relevant Research Questions

- What is relative contribution of *Denominator* versus *Numerator* to rising distribution network charge in California and many regions with significant distributed solar
  - Mechanical effect of less electricity withdrawn from grid on annual basis (same total cost less withdraws)
  - Grid integration costs to upgrade distribution grid to accommodate more distributed solar
- How should network pricing be reformed to eliminate incentive for inefficient bypass of grid supplier electricity
- Wolak (2018) "Evidence from California on the Economic Impact of Inefficient Distribution Network Pricing" address both questions
  - California has almost 10,000 MW of distributed solar capacity, by far the largest in United States
- Similar issues exist in other regions with significant amounts of distributed solar, such as Australia and Germany

Answers to Research Questions

- More than three-quarters of increase in distribution network charge between 2003 and 2020 due to grid upgrades to accommodate distributed solar
  - Implies substantial costs of inefficient distribution network pricing in California
  - Similar outcome likely in other regions with significant distributed generation
- Efficient network pricing argues for charging customer marginal cost of grid-supplied electricity and recover fixed cost of grid and "Other" costs using on monthly fixed-charge
  - Average annual marginal cost grid-supplied electricity is approximately 5 cents/KWh including losses in 2021
  - Uniform fixed charge for all households raises fairness issues

Answers to Research Questions

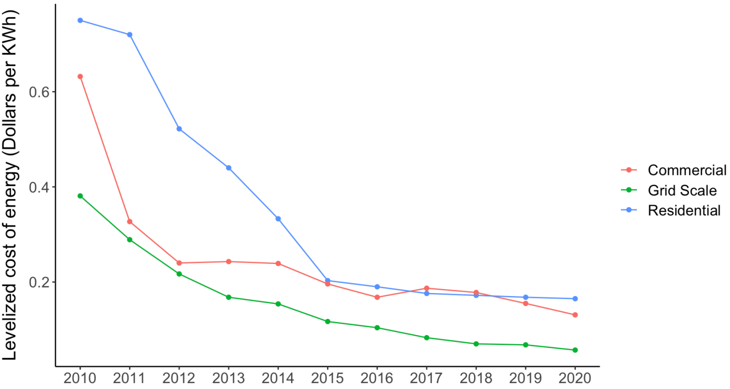
- Paper proposes to allocate fixed costs across customers using "willingness-to-pay" measure derived from customer's annual hourly distribution of electricity consumption
  - Different groups of customers could be assigned monthly fixed charges
  - Mechanism rewards used of storage devices to reduce variance of annual hourly demands
- McRae and Wolak (2020) Retail Pricing in Colombia to Support the Efficient Deployment of Distributed Generation and Electric Stoves" applies approach to case of Colombia
  - Mechanism able to make majority of households in all income deciles better off relative to existing tariffs
- Other proposals include income-based monthly fixed charge or housing assessed value-based charge, but this only works for residential customers

Centralized versus Decentralized Renewable Energy

Both grid scale and distributed intermittent wind and solar generation units can be used to reduce carbon content of electricity supply

Research Question: To achieve low carbon goals at least cost to consumers, where should investments in wind and solar should occur?

Levelized Cost of Energy from Distributed versus Grid-Scale Solar



The case for distributed wind and solar

- The case for distributed wind and solar investments relative to grid scale generation investments relies on two arguments:
  - distributed wind and solar reduces need for distribution network upgrades;
  - distributed wind and solar does not incur transmission and distribution network losses.

- However, typical transmission and distribution losses are not big enough to close the LCOE gap
  - $3\times$ LCOE Grid Scale Solar $\approx$ LCOE Distributed Solar
  - At most transmission and distribution losses can account for 15 percent of LCOE difference

$\Rightarrow$ Substantial network investment savings from distributed investments are needed to rationalize a higher support for distributed generation.

The New York Times

How New York City Is Turning Its Thousands of Roofs Into Power Providers

Manhattan now has the country's biggest array of solar panels on an apartment complex. The Bronx could soon have a bigger one.

"*even though not enough energy is generated to power all of the complex, the solar energy will take pressure off the power distribution network on hot summer days when demand from Con Edison's customers is peaking*"

(source: https://www.nytimes.com/2019/07/10/nyregion/nyc-solar-power.html)

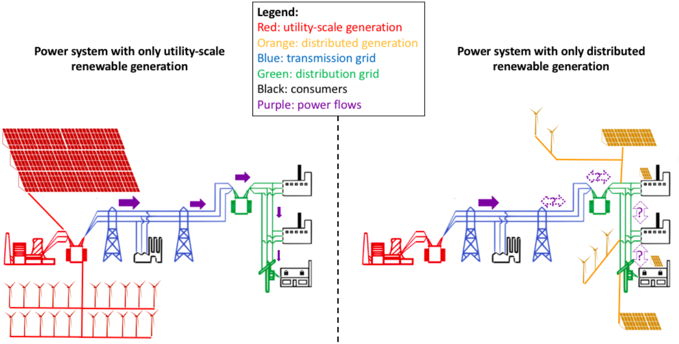
Research gap

- The extent to which distributed generation reduces the need for distribution future network investments is highly debated, particularly for distributed solar facilities
- Evidence typically comes from simulation models applied to hypothetical distribution network or a small number of actual distribution networks

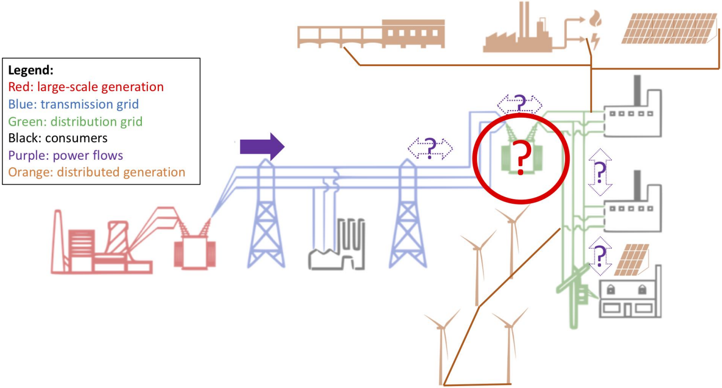
Empirical evidence based on actual power flows into distribution network is largely nonexistent.

- Astier, Rajagopal, and Wolak (2020) "Can Distributed Intermittent Renewable Generation Reduce Future Grid Investments? Evidence from France"
  - Study impact of investments in wind, solar, non-renewable thermal, renewable thermal and small hydro capacity on percentiles of annual hourly net load at distribution substation

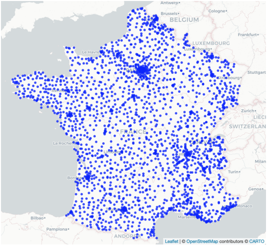
Grid-Scale vs Distributed Generation Units



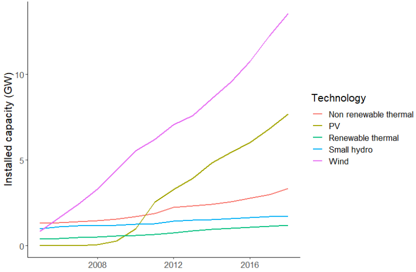
Distribution Substation



Substations and Distributed Generation Investments

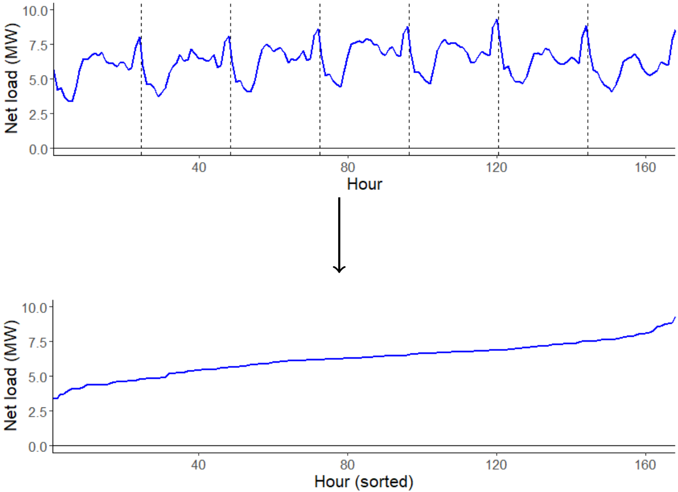


Hourly substation-level net load levels for 2,000+ substations from 1 Jan 2005 to 31 Dec 2018.

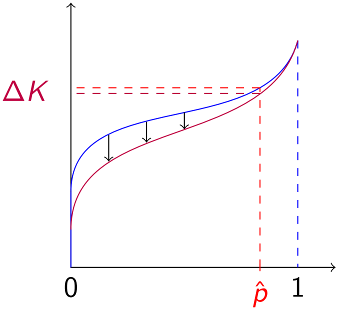


Substation-level installed capacity for each technology in each year.

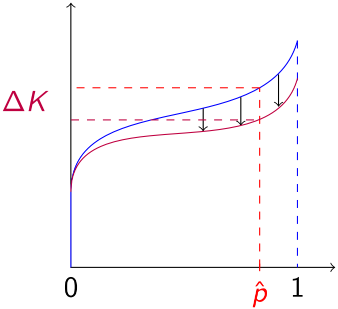
Net Load Duration Curve



Load duration curve and grid planning



Small capacity savings

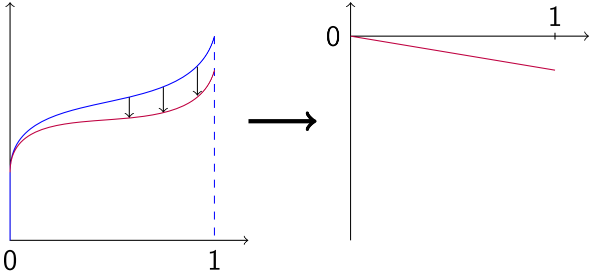


Large capacity savings

$\Rightarrow$ We keep track of quantiles of annual load duration curves for *each sub-station in each year*.

Quantile impact functions

General idea:



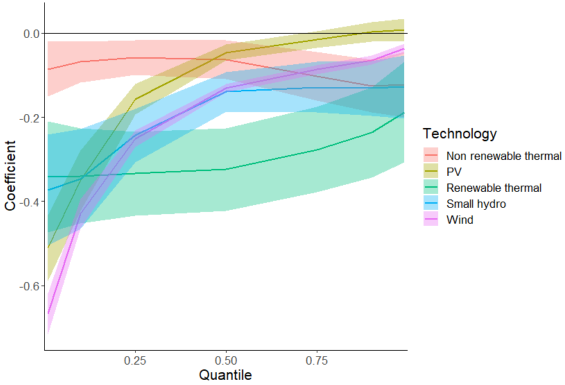
Change in the load duration curve Quantile impact function

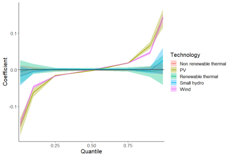
Econometrics:

$$Q_{q,s,y} = \sum_t \beta_{q,t} K_{t,s,y} + \delta_{q,s} + \delta_{q,y} + \epsilon_{q,s,y}$$

$\Rightarrow$ Fixing a given technology t and a given duration curve of interest, the tuple $(\hat{\beta}_{0.01,t}, \hat{\beta}_{0.1,t}, \hat{\beta}_{0.25,t}, \hat{\beta}_{0,5,t}, \hat{\beta}_{0.75,t}, \hat{\beta}_{0.9,t}, \hat{\beta}_{0.99,t})$ yields points on the estimated quantile impact function for that technology.

Main Results





- Hourly ramps are changes in hourly net load from one hour to the next.
- If anything, larger ramps are likely to increase distribution network costs.

Is Battery Storage Silver Bullet?

⇒ Under optimistic assumptions (perfect foresight, lossless and wear-free operations), adding battery storage induces noticeable impacts only at installation rates 5 to 10 times higher than currently observed rates in California.

- One Tesla PowerWall for each 3 KW rooftop solar system.

Policy take-away: At least for the case of France, benefits from deferring future grid expansions cannot rationalize a policy support for distributed wind and solar generation over utility-scale generation investments.

- Difficult to see how results do not carry over to other regions with large amounts of distributed solar such as California and Australia

Concluding Remarks

- Economists have much to contribute to design and implementation of least cost energy transition at wholesale and retail markets policies and transmission and distribution policy and regulation
  - Economists understand necessity of recognizing individual rationality constraint
  - Once market rules are set, all participants will optimize against them
- **Important Caveat:** Significant knowledge of power system engineering and regulatory oversight process governing electricity supply industry very helpful
  - Electricity is different from other products, cannot see product consumed although it is essential to modern life
  - Everyone connected to grid gets electricity or no one gets electricity