**Energy Law Outline**

Fall 2016

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# Course Introduction

1. *Energy Law* – a conglomeration of federal and state statutes and rules and policies, heavily affected by economic concerns
2. Electricity law’s overring mandates – (1) cheap, (2) abundant, (3) reliable; these can become threatened when forcing the transition to renewables, whether through laws, regulations, or policies
3. Key terms:
	1. *Capacity* – maximum electric output a generator can produce under specific conditions
	2. *Generation* – the amount of electricity a generator actually produces over an amount of time
	3. *Load* – demand
	4. *Demand/Load Response* – how to control consumption if the market needs it
	5. *Electricity Generation* –
		1. *Baseload plants* – plants that operate continuously to meet consumer demand; high capital costs, low operating costs
		2. *Peak-load plants* – operate when energy demand rises or “peaks,” e.g. dinner time until bedtime, sunrise until morning commute, all day long in some places; lower capital costs, high operating costs
	6. *Producers –*
		1. *Investor-owned utilities* (IOUs) – vertically integrated monopolies that earn a “rate of return” for their investors; about 65% of all utility electricity generation
		2. *Independent Power Producers* (IPPs) – non-utility generators that own power plants and sell “wholesale” electricity to others; produce about 35% of electricity
	7. *Transmission* – high-voltage, long-distance delivery of electricity over power lines
		1. “*The Grid*” – connected power lines, came together haphazardly, management can be poor, congestion is a problem; in the United States, three main “grids,” called interconnections
	8. *Distribution/Retail Sales* – low-voltage delivery of electricity to end-users; rates set by PUCs, question of whether consumers should have a choice
		1. *Electricity Sales* –
			1. *Wholesale Sales* – sales of electricity to entity other than the end-user, e.g. from IPP to utility to customer
			2. *Retail Sales* – sales to end-user, e.g. utility produces electricity and sells to own customers
	9. *Federal Agencies* –
		1. *Department of Energy* – overall policy director
		2. *Department of Interior* – federal lands where resources are located
		3. *FERC* – natural gas and wholesale electricity sales and transmission, hydropower, and other
		4. *NRC* – nuclear power plants
		5. *EPA* – pollution control
	10. *State Agencies* –
		1. *Public Utility Commissions* (PUCs) – rate regulation, “franchise approval” and utility planning review and approval; sometimes going beyond to set more aggressive rules and requirements
			1. *Siting approval* – land use agencies, other agencies may prohibit or restrict

# Utility Regulation

1. The Rise of the Electricity Monopoly
	1. *Natural Monopoly* – a *monopoly*, sole provider of particular goods or services, in an industry in which it is most efficient for production to be permanently concentrated in a single firm
		1. Natural monopolies tend to form when: (1) High upfront capital costs and/or other barriers to entry, (2) ability to achieve economies of scale and serve entire market, (3) low *marginal costs* – costs to produce last unit or to serve last customer
	2. Theory of traditional electricity system as a natural monopoly – (1) high costs/capital intensive, (2) barriers to entry – no need for duplicative infrastructure/siting challenges, (3) price per unit often relatively low
	3. Theories of Monopoly Regulation, why regulate monopolies, public interest v. public choice –
		1. *Public interest* – monopoly is controlled for delivery of a reliable service or good in the public interest; in the electricity sector – rates set at competitive levels, guaranteed access to good or service
		2. *Public choice* – government regulates at behest/for benefit of regulated industry; in the electricity sector – guaranteed rates of return, guaranteed service areas – protection from competition
	4. *Vertical monopoly* – one company owns generation, transmission, and distribution
		1. Deregulation – could competitors enter the market through, e.g., contracts? What happens if competition at the generation end and a monopoly in transmission, risk of monopsony?
			1. *Monopoly –* one provider of service or commodity (one seller) and many captive customers (many buyers), risks – denial of service, high rates
			2. v. *Monopsony* – many providers of service or commodity (many sellers) and one customer (one buyer), risks – low prices for producers, less production, public interest concerns
	5. Common law rules for utilities – (1) service to the public, (2) monopoly power – may change with technology, (3) fixed territory, (4) duty to serve – no discrimination, (5) reasonable rates
	6. Power of the PUCs – (1) assign territory, (2) regulate procurement – through certificates of public convenience and necessity (CCNs), (3) set service rates, (4) regulate rates – just and reasonable, (5) approve spending – review major capital expenditures to make sure they’re prudent, (6) control abandonment
	7. Policy questions regarding monopoly regulation –
		1. Is it good for the ratepayers?
		2. Is it good for the companies and their investors?
		3. Is it good for potential competitors?
		4. Should it even apply to the electricity sector?
2. Fundamentals of Monopoly Regulation
	1. *The Proprietors of the Charles River Bridge v. The Proprietors of the Warren Bridge* (S.Ct., 1837)

**H:** Upholds the Warren Bridge charter, e.g. not in violation of the Constitution’s Compacts Clause, because government cannot contractually imply exclusivity (e.g. create a monopoly), holding in favor of the public interest – must construe in favor of the states (idea imported from English common law), concerned from precedent set for industries (e.g. the railroad industry, never ending litigation), nothing about exclusivity in the contract, societal concept that progress will stand still if bar competition

**Rule:** When dealing with something in the public interest, going to operate in favor of the public (here the state) (creating a public interest test)

**D:** Would not have upheld the Warren Bridge charter in favor of investment – if no monopolies no progress because will curb investment in risky projects, not dealing with a monopoly here because a monopoly is an exclusive right that takes something away from the public that they otherwise would be able to do (arguing over understanding of what a monopoly is, his conception is no longer common belief)

* 1. *Munn v. Illinois* (S.Ct., 1876)

**H:** Upholds Illinois legislation to fix price ceilings for grain (e.g. ratemaking) because legislature can regulate monopolies and set rates – e.g. no takings claim

**Rule:** (To determine when something can be subject to regulation) If affected with the public interest, something is in the public interest when it is”used in a manner to make it of public consequence and affect the community at large”

**D:** Would not uphold – interfering with the private property; only affects public interest where government has bestowed public interest, doesn’t just exist in private property no matter how important that property is

* 1. *Nebbia v. New York* (S. Ct., 1920) – “affected with the public interest” means “no more than that an industry, for adequate reason, is subject to control for the public good”
1. Monopoly Regulation in Practice
	1. Cost of Service Regulation
		1. Cost of Service Rates (e.g. Ratemaking)
			1. Purposes – (1) to ensure utility’s financial integrity and attract investors and (2) to protect ratepayers from exploitive rates
			2. IOUs – companies with private/public investors
				1. Typically – preferred stockholders (investors who are guaranteed a dividend) v. common stockholders (investors who have purchased some of the company’s stock, they earn money either through dividends or when the value of the stock increases)
				2. If IOUs need money, they will – take out a loan, issue more preferred stock, issue more common stock
				3. IOUs need revenue to pay back those loans/make stock valuable – done through the ratemaking process
		2. The Ratemaking Process – set revenue requirement (how much utilities are entitled to earn) and then set consumer rates (“rate design”)
			1. (1) Utility gets PUC approval to invest in new power plant (obtains a CCN)
			2. (2) Utility makes investment in plant, puts plant into service
			3. (3) Utility seeks recovery through ratemaking for expenses made in power plant
				1. Utility won’t get to recover full cost of plant in one year, the costs will be spread out over the estimated lifespan of the plant, based on the plant’s value and depreciation
			4. (4) Rate cases usually happen every three years and are prospective (i.e. the PUC is deciding how much the utility should earn in the upcoming three years)
				1. Rate cases determine how much the utility will earn from ratepayers
				2. Expenses based on “test year”
		3. The Basis of Ratemaking: The Rate Base, Rate of Return, and Operating Expenses
			1. R = O + B\*r or R = O + (V-D)\*r
				1. R = *revenue requirement* – the amount the utility needs to recover from its customers to cover its costs
				2. O = *operating expenses* – variable expenses, i.e. fuel costs, labor costs, etc.
				3. B = *rate base* = V-D

V = value of the asset (e.g. the coal plant)

D = depreciation

* + - * 1. r = *rate of return* – return on investment
			1. The Rate Base and Rate of Return
				1. *Rate Base –* capital expenses – physical infrastructure + cost of raising capital (e.g. stocks, dividends, etc.)

E.g. Power plants, transmission lines, property purchases, stocks (portfolios, prospectus, dividends), affiliated expenses

* + - * 1. *Rate of Return –* percent earning on the rate base, may go up or down if utilities need more revenue or are over-compensated

Calculate: Debt (based on interest rate for taking out loan) + preferred stock (based on set rate of return) + common stock (two methods – market-determined (investor expectation) and comparable earnings (based on what capital can earn in other investments with comparable risk))

Example: $6,000,000 plant, ½ of funding from loan of $3,000,000 at 8% interest rate, 1/6 of funding ($1,000,000) from preferred stock at 9% rate of return (set by company), 1/3 of funding ($2,000,000) from common stock with 12% rate of return (set by market)

Rate of return = ½(8%) + 1/6(9%) + 1/3(12%) = 4% + 1.5% + 4% = 9.5%

But: Lots of guess work involved

* + - * 1. Implications of B\*r – incentive to build to earn more money

Mitigating rules – prudent investment (through CCNs), used and useful rule

* + - 1. Operating Expenses – no rate of return on operating expenses
				1. Set based on test year expenses (historical), adjusted for anticipated future needs (but not one-time expenses) or if test year is abnormal, expenses must be prudent
			2. Ratemaking in Action
				1. *Iroquois Gas Transmission System v. Federal Energy Regulatory Commission* (3d Cir., 1998)

**H:** Reasonable to put civil and criminal litigation expenses (but not settlement penalties) into the rate base (B)/pass onto ratepayers to make a profit off of because lawyers fees commonly associated with costs of building (obtaining permits, defending when violate permits), FERC has the burden of showing unreasonable (FERC tried impermissibly shifting that burden to Iroquois), litigating may save ratepayers money though where monopolies almost never prudent (*Mountain State I* & *II*) (interests in compliance, alleged by FERC, are too amorphous, may constrain utility actions that benefit ratepayer through efficient pipeline construction)

*Mountain State I* – don’t presume imprudent

*Mountain State II* – but in antitrust cases may presume imprudent

**Rule:** Was the decision reasonable that it would benefit the ratepayers? Were litigation costs prudent? (e.g. no malpractice, reasonably prudent litigator, took any reasonable settlement offers)

**J:** Remanded to FERC to determine whether prudent for criminal violations

**FERC:** On remand held that the burden is on the defendant to show criminal litigation expense were reasonable/prudent

**C:** Distinguishes this case because criminal violations, meaning willful and knowing violations, accuses M of incentivizing criminal conduct or at least walking close to line of non-compliance because will be presumed reasonable; concurs that FERC needs to explain but doesn’t think this means FERC cannot refuse the rate increase

**Takeaways:** Continuing decisions/every dollar spent on further activity needs to be prudent not just capital expenses and initial decisions

**Note:** In most states companies have the burden of showing expenses were prudent and should be placed in the rate base

* + - * 1. *In re Philadelphia Electric Company* (Pa. PUC, 1978)

**Test Year:** Usually the year before to figure out actual expenses; adjustments – do not include unrepresentative expenses, increase/decrease test year results based on future growth, lower costs, etc.; ultimately end up with the “O” for the period of the rate and plug into the formula

**I:** (1) Meter reading? (2) Abnormal maintenance, fuel, interchange? (3) Wage adjustment?

**H:** Costs for meter reading may be placed in the operating expenses, abnormal fuel costs, maintenance, and interplay and overtime may not be placed in the operating expenses

**R:** (1) Ok to include costs not included in the test year in the future and it’s good for customers; (2) general rule that abnormal costs are utility’s to bear (e.g. investors not ratepayers pay); (3) too high, utility is reducing overtime (example of how test year data gets adjusted)

**Note:** Request to amortize costs means the company wants to spread them out over period of time, i.e. recover in installments

**Takeaway:** Ratemaking is prospective, test year intended to be representative but sometimes it isn’t

* + - * 1. The Process ^: R = O + B\*r

R = total revenue the utility presumed to get

Translates into the rates the utility may charge (for example, $.10/kWh)

The utility is then stuck with the *rate* and may charge higher rates only if it goes through another ratemaking

If utility’s actual expenses are lower, can still charge same rates and generate more profits

If utility’s actual expenses are higher, utility will earn fewer profits

* + - * 1. *Southern California Edison Company v. Public Utilities Commission* (Cal., 1978)

**Fuel Adjustment Clause:** Varies by state, here structured prospectively requiring that every year or month utility calculate load\*demand and sought adjustment (not full blown ratemaking case) if that calculation varied from rate by any certain amount, intention to make sure rates fit the market; essentially a refund but refund *would* be retroactive ratemaking so not calling it that

**I:** (1)Does the prohibition against retroactive ratemaking apply? (2) Can you use FAC to get your rate of return met?

**H:** (1) FAC not retroactive ratemaking but rather informal, administrative action, not a full-blown ratemaking case; (2) no, utilities bear the risk of higher or lower costs

**D:** FAC clearly making rates so *is* ratemaking

**Note:** FACs are controversial for the fear that will unduly shift the cost of expensive fuels onto the customers

* + - * 1. *City of Cleveland v. Public Utilities Commission of Ohio* (Ohio, 1980)

**H:** Advertising expenses may be put in the operating expenses when it is informational or regarding conservation but not when it is institutional, promotional, or charitable

**Rule:** Advertising must be for the primary, direct benefit to customers; consider if it’s in the benefit of the public or investors

* + - * 1. *Legislative Utility Consumers’ Council v. Public Service Company* (N.H., 1979)

**H:** Cannot include appliance/appliance repair in the rate base/pass onto customers because it is not apart of service to customers and it’s not ongoing (shouldn’t be in future rates anyway); relates to non-utility operations and there was testimony in the record that the company would no longer be engaged in the appliance business as of the effective date of new tariff

* + - * 1. ^ Takeaways – setting the “R” is very important as it establishes the presumptive rates utilities will earn

General rules: B must be prudent and used and useful, O must be prudent and primary benefit to consumers and not atypical

Once PUC sets the R it will then set consumer rates (R/amount of electricity = rate design and fixed outcome of ratemaking)

E.g. $100 million/1 billion kWh = $0.10/kWh

* 1. Judicial Review of Ratemaking Decisions: Early Cases and the Role of the Courts
		1. Rate Regulation: R = O + B\*r or R = O + (V-D)\*r
			1. In concept, B (rate base) may decline to zero for a given asset but in many cases value in the asset will remain as even if the asset depreciates to zero it will still have some fair market value if it were sold, stock and other capital assets will remain even if a facility gets paid for
		2. What is the “value” of the rate base – original value? Current fair market value? Something else?
		3. *Smyth v. Ames* (S. Ct., 1898)

**Rule:** Fair value test, need to set rate base value based on the “fair value of the property being used” – original costs of construction, amount expended in permanent improvements, amount and market value of bonds and stocks, present costs of construction (production costs), probably earning capacity of the property, sum required to meet operating expenses (embedded into the rate base for some industries)

**Note:** Set up a heavy degree of scrutiny of rates by the courts (judicial review probes the process for setting rates), making courts act like regulators anytime it had a rate case it didn’t like

* + 1. *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia* (S. Ct., 1923)

**Rule:** Present, reproduction value (v. construction costs) – to incentivize utilities to continue to invest/build to provide services to us, idea that if depreciates down to zero that utilities will stop investing (will stop making a profit) and to make it profitable must continually reassess value (if the property has increased in value, the company is entitled to the benefit of that increase)

**Rate of return:** Equal to what’s generally being made at the same time and in the same part of the country on investments in other business undertakings that are attended by corresponding risks and uncertainties *but* no Constitutional right to profits earned in highly profitable/speculative ventures

**Rate regulation:** Intended to earn a return on the value of the property which it employs for the convenience of the public

**Goal:** Assure financial soundness of utility, maintain credit and enable it to raise money

**H/R:** Court quotes a number of other decisions to determine how to calculate the value of the rate base ^ (turning *Smyth* into a *per se* rule)

**Note:** High water mark for what happens when you continually reassess the value of the asset

* 1. Judicial Review of Ratemaking Decisions: Later Cases and the Shifting Role of the Courts
		1. *Federal Power Commission v. Hope Natural Gas Co.* (S.Ct., 1944)

**Company Wanted:** Rate base calculated either on reproduction cost or trended original cost, i.e. what would take to build facility now or applying 1938 material/labor prices to work done since 1898

**Commission Gave:** Actual legitimate cost minus depreciation plus additions

**H:** Abolishes the fair value test and establishes the end results test for ratemaking because the fair value test is circular; return should be commensurate with returns on investments in other enterprises having corresponding risks and should be sufficient to assure confidence in financial integrity of the enterprise to maintain credit and attract capital

**Rule:** End results test – if end result (percentage return that utility will earn) is fair, methodology to get there doesn’t matter, high burden to plaintiffs challenging a PUC’s rates, deference to PUC; rate will be viewed in its entirety

**Valid rates:** If meet basic parameters at the end of the ratemaking process then must uphold – enable company to operate successfully, maintain company’s financial integrity, attract capital, compensate investors for risks assumed

* + 1. *Market St. Ry. Co. v. Railroad Commission of State of California* (S.Ct., 1945)

**F:** Quality of service declined even as rates increased, never asked for higher rates even though unable to maintain operations under $.07

**Rule:** *Hope* requirement that rates must be adequate to attract investors/capital does not apply where market forces or otherwise has resulted in the enterprise dying, *Hope* is not a test to prop up dying enterprises, at some point utility/monopoly regulation will let enterprises/industries die (technology/competition v. monopoly); *Hope* said regulation does not guarantee a profit, prohibition against taking cannot be applied to insure values or to restore values that have been lost by operation of economic forces

* 1. Applying *Hope* to Ratemaking: Balancing the Needs of the Utility (and Its Investors) with the Needs of the Ratepayers
		1. Two aspects of ratemaking
			1. Statutory requirement that rates be “just and reasonable” – need to be balanced on both sides, ratepayers may challenge rates under this requirement
			2. Constitutional implications – rates may amount to an uncompensated taking – if utility challenges rates under statutory requirement, will usually also raise a Constitutional claim
		2. Prudent investment v. used and useful
			1. PUC approval process
				1. Utility goes to PUC to get a CCN – the PUC’s blessing, project is necessary, demonstration of prudence
				2. Utility builds the project – may take years and, today, billions of dollars
				3. Utility puts the project into service for the public
				4. Only after the project is built may the utility seek to add the project to its rate base
			2. Prudent investment rule – so long as an investment was prudent when made, the utility is entitled to put the investment in its rate base; almost all states have requirement of ongoing demonstration of prudence – if it becomes clear that an investment is no longer prudent, any costs expended on the project after that point are not recoverable
			3. Used and useful rule – any project that comes online and is “used and useful” in the service of the public may go into the rate base, if project does not come online it is not used and useful and there’s no recovery under the strictest application
				1. Hybrid versions – three general options

Prudent investment + used and useful – investment must be prudent when made and throughout the construction process and investment must be used and useful

Recovery for prudent investments in the operating expenses, even if not used and useful

Some recovery for prudent investments in rate base, some in operating expenses, or some other combination (e.g. some recovered, some not)

* + 1. Recovery for Failed Projects: Applying the Used and Useful Test in the Event of an Otherwise Prudent Investment
			1. *Jersey Central Power & Light Company v. Federal Energy Regulatory Commission* (D.C. Cir., 1987)

**F:** (1) $397M investment, (2) charges on debt (interests on loan), (3) preferred stock charges, (4) common stock

**Jersey Central:** Wants to (1) put in operating expenses – amortize, (2) put in rate base, (3) put in rate base, (4) investors eat

**FERC:** (1) Yes, (2) no, (3) no, (4) yes *and* no to increased rate of return (r)

**I:** (1) Did FERC follow its own rules (admin law issue)? (2) Did FERC deal with the end results test properly? (3) What’s at stake in taking claims like this?

**H/C:** (1) No – no ironclad rule about excluding costs from rate base under its “used and useful” policy, FERC uses a Construction Work in Progress (CWIP) policy that allows some construction costs to go into the rate base right away, it can’t therefore say “rules are rules” without more explanation; (2) no, FERC never even calculated the end result; (3) looks like a taking so need to remand to figure out end result, the property taken is the investment not the property used

**C:** (3) Unclear if it’s a taking, property taken is not the investment, the real interest is the balance struck – utility business represents a compact that utility investors get stability in earnings/value and ratepayers get universal, non-discriminatory service and protection from monopolistic profits

**D:** (1) FERC did follow its own rules and parts of Jersey Central’s recovery request did not conform, (2) ^ that’s because *Jersey Central* filed its case prematurely, (3) difficult to determine a taking in the rate regulatory context because there’s no deprivation of typical property interests but cannot be based on prudent investment rule only, there is not guaranteed return on investments just like loss of future profits is not a legitimate basis for a takings claim, question is whether investor/ratepayer interests are balanced

* + - 1. *Duquesne Light Company v. Barasch* (S.Ct., 1989)

**H:** Change in law that costs shall not be included in the rate base/rates until proven used and useful (strict used and useful requirement) not an unconstitutional taking because impact on utilities would be negligible and not unconstitutional because end results are minimal and the utilities had notice

**Limits:** May be a taking if rule changes too often so that utilities don’t have sufficient notice (holding not unlimited)

**C** (Scalia): Taking is the investment (agreeing with M in *Jersey Central*, minority view) – prudent investment may become Constitutional standard because property interest taken is the investment, if not going to give “fair value” to the property then need to protect the interest

* + 1. Paying for Ongoing Capital Projects: The Construction-Works-in-Progress Rule
			1. *Legislative Utility Consumers’ Council v. Public Service Company* (N.H., 1979)

**CWIP:** (Construction works in progress)allows costs of capital to go into rate base while construction is underway, meant to mitigate some of the harshness of used and useful rules

**I:** Do CWIPs violate the used and useful standard? i.e. Can you have a CWIP rule in a “used and useful” jurisdiction?

**H:** Rule that construction costs may go into the rate base while construction is underway is a factual issue and does not violate used and useful as required in legislation because it’s a reasonable balance and that’s all that’s required (to whether it is “just and reasonable” to require current ratepayers to pay for plant under construction, i.e. whether it is detrimental to current ratepayers and a windfall to future ones)

* 1. Rate Design – the process of deciding how much customers should pay for their electricity
		1. Purposes
			1. Translating the revenue requirement (R) into costs per kWh
			2. Promoting/deterring electricity usage
			3. Retaining utility customers, especially industrial customers
			4. Achieving policy goals, e.g. subsidizing low-income ratepayers
			5. Linking rates to the costs customers “cause”
		2. Three aspects
			1. Demand charges – fixed assets (i.e. power plants) necessary to satisfy demand, often based on peak demand
			2. Energy charges – costs of the power consumed, usually reflected in fuel charges
			3. Service charges – costs of implementing service, e.g. meter reading, billing, fixing problems, etc.
		3. Embedded v. Marginal
			1. Embedded – taking the same costs from the revenue requirement and allocating them to different customers/customer classes
			2. Marginal – based on adding service, meaning not on average costs of the whole system but on incremental costs of expanded system
				1. Idea that you pay for the type/cost of power you demand
		4. Cost Apportionment
			1. Customers – divide among classes + among customers within classes
			2. Total energy use – divide based on actual electricity usage
			3. Demand – divide based on how much demand, i.e. how much capital investment customers cause
		5. Rate Design within Classes
			1. Customer charge = basic services + some demand – metering, payment processing, distribution lines and balancing, power supply
			2. Energy charge = based on amount of consumption, used in blocks (declining and inclining rates)
		6. Inclining block rates – costs per kWh increase as consumption increases; arguments in favor –
			1. Conservation incentives – higher prices = lower consumption
			2. Additional subsidies by large users (demand charges effectively shifted more onto the larger users); net metering debate involves these dynamics
		7. Declining block rates – costs per kWh decrease as consumption increases; arguments in favor – 
			1. Equity to large consumers – the first large block covers “demand” + customers costs, which are smaller for commercial customers than residential customers
				1. Demand – peak demand driven by residential consumers
				2. Customer costs – higher for residential customers in the aggregate
			2. The other blocks primarily represent fuel costs; the demand and service components fade out because they’re covered in earlier blocks
			3. More sales from utility = financial integrity
		8. Time of use rates
			1. Usually for large consumers – moving into residential area
			2. Pay a premium when they use energy at peak times, will pay less during other times
			3. Reflect idea that utilities will pay higher costs to supply peak power – ramp up own expensive plants, higher market rates based on supply v. demand and congestion
		9. Marginal Pricing
			1. Time-based rates and marginal pricing – most energy bills reflect average costs, e.g. they usually include standard rates for peak and off-peak power, even where they have different peak and off-peak rates they are not necessarily tied to actual costs
			2. Marginal rates – meant to encompass full costs (infrastructure, transmission, electricity) of that next kWh of power – more reflective of actual costs *caused* by the customer
			3. Calculate cost of purchasing/delivering that next kWh of electricity – peak rates, off-peak rates, intermediate rates
			4. Apply that cost to the actual amount used by ratepayers
			5. May need backstop if marginal rates too low
		10. Straight fixed-variable rates
			1. Meant to remove utility incentive to sell more *and* increase customer incentive to use less
			2. Fixed rates = capital, labor, rate of return, etc. – divided among customers, once calculated the utility cannot earn more than these fixed rates
			3. Variable rates = fuel, power purchases, etc. – based on customers’ actual consumption, do not include a rate of return
		11. Limits on rate design strategies – price inelasticity or misdirected elasticity 
			1. Can’t respond to prices – essential services without backup, no financial room to maneuver, no alternatives
			2. Won’t respond to prices – electricity costs not a major behavioral motivation
			3. Response to price changes in other sectors – higher rates = e.g. eat out less
		12. Information/communication gaps
			1. Billing after-the-fact – monthly/yearly/other bill cycle inconsistent with behavioral changes, average time-of-use or seasonal rates over year (mitigates price shock but minimizes responses to rates)
			2. Information disparity – general time-of-use rates insufficient in comparison to real-time information (stay tuned for “smart” meters)
		13. Ratemaking/Rate Design Issues
			1. The traditional approach to rate design – revenue requirement is translated into a rate set on expected retail sales, differential rates are also set based on anticipated sales
			2. Implications
				1. Utility’s actual revenues are based on amount of electricity the utility sells – if sells more or keeps costs lower than expected, it makes more profit than the B\*r would otherwise suggest; if sells less or has higher than expected costs, it will make less of a profit than expected
				2. Why is this a challenge? The next rate case will take into account what happened in the past

If a utility made more profit than expected, it may face lower rates (price per kWh) → will need to sell more electricity in the future – more sales = more need for power = more assets in B = higher R = higher rates = less consumption?

If utility made less profit than expected, it may get a higher R/higher rates → customers may use less electricity = less justification for new assets = lower B = lower R = lower rates = more consumption?

* + - * 1. Until recently, the trend was towards more energy consumption = higher B = higher R = higher rates = increased consumption (demand not responding to costs)
				2. But if you have lower demand + lower R and demand not increasing even if costs drop, what happens to the utility bottom line? Do we need to compensate utilities differently? (e.g. the utility “death spiral” dilemma)
				3. Other issues?

Information/resource disparity – prudency review is not always effective

Time and cost in rate cases is massive

Over-investment and under-investment problems

Maybe time to rethink our ratemaking/rate design assumptions

1. Utility Regulation Beyond Ratemaking: Procurement, the Duty to Serve, the Utility Franchise
	1. Procurement/Resource Acquisition
		1. Procurement, Risk, and the Least-Cost Mandate
			1. General rules
				1. Least cost – short term/long term
				2. Low risk – translates into least cost over long term
				3. Fuel diversity – translates into least cost
				4. Abundant, reliable power
				5. Public interest – usually a combination of the above – least cost, reliable, abundant, low risk
			2. New rules
				1. Specific resources, e.g. renewable portfolio standards (RPSs)
				2. Emissions limitations
				3. Technology incentives
			3. Procurement – CCNs, contracts, and risk assessment, utilities will have to get regulators’ approval to build own resource or enter into long-term contract for power purchases
			4. Order Disapproving Petition by Excelsior Energy, Inc., for Approval of a Power Purchase Agreement (Minn. Pub. Util. Comm’n, 2007)

**H:** Denied petition from Excelsior Mesaba Plant to build an IGCC coal power plant due risk-exposure – unreasonable operational risks and unreasonable financial risks – and it not being least-cost (would’ve been twice the price for consumers to purchase from this plant) – unreasonable on its face

**Takeaway:** Just because it’s an innovative project doesn’t mean the utility can skirt other procurement obligations; demonstration of how traditional procurement rules can affect building decisions

* + 1. Integrated Resource Planning and Utility Resource Acquisition
			1. Comprehensive utility planning – considers supply-side and demand-side; long-term outlook – usually 10-20 years, anticipated demand forecasts, strategy to meet demand; regular updates – every 2 years unless event triggers revision sooner; focus on least cost resources
			2. How states use them
				1. Filed, without review, but affect future decisions
				2. PUCs review and approve them – utilities must follow them once approved/“acknowledged”
				3. Treated as suggestions that do not comprise a meaningful part of planning
				4. No all states use
			3. Oregon
				1. Utility develops IRP
				2. Subject to public participation and “acknowledgement” by PUC
				3. If action PUC later takes is acknowledged in IRP, most likely will be considered prudent during CCN or contract process – affects recovery of investment under ratemaking processes
				4. Evaluate resources on a consistent and comparable basis
				5. Comparisons must consider risk and uncertainty
				6. Portfolio selection should be best combination of expected costs and associated risks and uncertainties for utility and customers
				7. Must be consistent with long-run public interest as expressed in Oregon and federal energy policies

 

* + - 1. In the Matter of PacifiCorp, dba, Pacific Power & Light Co. (OR PUC, 2007)

**H:** PUC did not give its blessing to build baseload power plant “on the backs of Oregon consumers”; may still build but not with PUC’s blessing?

**R:** Forecasted load too high; need peak energy not baseload and didn’t explain why baseload is the best option; demand-side management, short-term purchases, and distributed resources are better (will mitigate CO2 risks); mitigating provisions are not adequate, need to explore other options first; hasn’t shown what will happen with excess supply – wholesale coal sales risky with California’s law and RPSs; problems with competitive bidding – RFP is in isolation from other resource acquisition decisions (not sure how it will access overall costs and risks), delay in coal investment might be wise with regulatory uncertainty

**Note:** PacifiCorp knew it was overbuilding and hoped on selling to California but California had just enacted a new law and RPS so would be for short-term sales only and likely lessened demand for coal-powered energy

* 1. Service
	2. Scope of the Monopoly

# Electricity: Jurisdiction and the Federal Power Act

1. FPA Jurisdictional Overview
	1. IOU to IOU → wholesale → FERC regulates
	2. IOU to end user → retail → state regulates
	3. IOU to municipality (uses some power for own uses) to end user → retail and retail → state regulates
	4. IOU to end user across state line (interstate retail) → retail → state regulates
		1. State are not expressly preempted from regulating interstate retail transactions, transactions are usually between a power plant and an industrial user subject to contracts, source state usually regulates
2. The *Attleboro* Gap
	1. *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co.* (S. Ct., 1927)

**F:** RI sells electricity to MA utility pursuant to a contract but rates in contract are bad for RI and MA won’t renegotiate, RI seeks rate increase from RI PUC because it MA rates don’t change will need to increase rates to RI consumers, RI PUC permits increasing rates to Attleboro

**H/Rule:** States cannot regulate wholesale transactions in interstate commerce (unconstitutional)

*Pennsylvania Gas* – gas from PA to NY for distribution to customers, NY PUC regulating rates to customers, will affect rates PA gas company may charge, ok because regulating local, effect on interstate commerce is indirect, rates are to local consumers (i.e. retail)

*Kansas Gas Co.* – gas from OK and KS to MO, PUC regulating rates from OK to KS to MO not rates to customers, not ok because direct regulation of interstate commerce, this is wholesale

**Attleboro Gap:** Retail sales across state lines still regulated but not wholesalesales across state lines because states have no authority and the federal gov’t has no statute providing it authority (gap filled with the Federal Power Act)

* 1. “The *Attleboro* Gap”
		1. States cannot regulate interstate wholesale electricity sales
		2. Federal gov’t not regulating interstate wholesale electricity sales
		3. Means ratepayers subject to unregulated wholesale electricity rates = high retail rates or utilities get squeezed if PUCs won’t increase retail rates or utilities do not purchase wholesale electricity from interstate sources (but not always an option)
1. The Legislative Response to *Attleboro*: The Federal Power Act
	1. Federal regulation over: Transmission of electric energy in interstate commerce, wholesale sale of electric energy in interstate commerce, by “public utilities” (private entities, not public entities)
		1. Interstate commerce = energy transmitted from a state and consumed at any point outside the state
		2. Wholesale = sale of electric energy to any person for resale
	2. No federal jurisdiction over: The United States, states or political subdivision (meaning municipalities exempt), electric co-ops under REA or that sell less than 4M MWh/year
	3. § 201(a)–(f), Declaration of Policy
		1. § 201(a) – federal regulation of those matters which are not subject to regulation by the states
	4. §205(a)–(d) – gives FERC authority to set rates for transmission and wholesale sales in interstate commerce – must be just and reasonable and no undue preference or advantages (i.e. must be nondiscriminatory)
	5. § 206(a)–(d) – gives FERC authority to fix rates that are determined to be unjust, unreasonable, and discriminatory, include right to issue refunds after complaint filed/case begun
	6. Filed rate doctrine – once FERC sets a wholesale rate, states cannot effectively override it through retail ratemaking, basically have to allow the rate to pass through
	7. Regulation of Wholesale Sales and Transmission in Interstate Commerce
		1. *Federal Power Commission v. Southern California Edison Company* (S. Ct., 1964)

**H:** FERC/federal gov’t has plenary authority over wholesales in interstate commerce and therefore over sale between Southern Cal Edison and city of Colton (not California’s PUC)

**R:** Federal gov’t has statutory authority to regulate wholesale sales [in interstate commerce], states do not have the power to regulate IOUs at wholesale

**Rule:** Federal gov’t regulation if (1) wholesale, (2) sale, (3) in interstate commerce (no case yet has overcome this test)

* + 1. *Federal Power Commission v. Florida Power & Light Company* (S. Ct., 1972)

 **H:** FERC/federal gov’t has wholesale authority even where not directly connected to another state

**Rule:** Per FPA language, FERC has regulatory authority any time any electrons cross state lines

**R:** Interstate commingling – everything is connected on the grid by the grid’s nature that operating at a steady state (supply = demand), funneling/bus analogy that showing buses entering and leaving station is adequate to show that energy is moving in interstate commerce

**D:** No wholesaler can avoid federal regulation

**Note:** D correct (with the exception of Texas, Alaska, and Hawaii), so far no one has won the challenge that their energy is not crossing state lines

* + 1. Interstate commerce for commerce clause v. for FPA
			1. Commerce clause – may include wholly intrastate activity with a substantial effect on interstate commerce subject to federal regulation
			2. FPA – need to show actual movement of electricity over state lines, but test is pretty forgiving
		2. *Federal Power Commission v. Conway Corporation* (S. Ct., 1976)

**I:** Can FERC in ratemaking consider arguments that wholesale rates are discriminatory when considered in relationship with retail rates?

**FERC:** Must only set just and reasonable rates for wholesale, cannot consider allegations re anticompetitive impacts of the wholesale rates, not supposed to address discriminatory rates by raising retail prices

**H:** FPA requires FERC to prevent unreasonable difference in rates, just because FERC lacks authority over retail rates does not mean it lacks authority to consider disparate impacts, “just and reasonable” rates are hardly so precise – they fall within a zone of reasonableness and may be unreasonable based on the relationship of wholesale and retail rates to each other; FERC has jurisdiction, §§ 205 & 206 violation, rates need to be just and reasonable and nondiscriminatory, need to consider end-users (not just wholesale) because wholesale rates drive retail rates and reasonable rates aren’t set in a vacuum but rather the market is considered too

* 1. Public Utilities under the Federal Power Act
		1. *City of Redding, California v. FERC* (9th Cir., 2012)

**Rule:** Defining public utilities as private entities (re IOUs), excluding public entities (gov’t utilities or other exempt entities, i.e. rural electric co-ops)

* + 1. *Arkansas Electric Cooperative Corporation v. Arkansas Public Service Commission* (S. Ct., 1983)

**H:** Arkansas may regulate wholesale rates from cooperatives to its members (both non-public utilities) (exempted from federal regulation) because not expressly/impliedly preempted by the statute (nothing in language, history, or policy of the FPA that would prohibit), *Attleboro* does not prevent this exercise of jurisdiction as the modern dormant commerce clause applies (instead of the anachronistic dormant commerce clause, see rule below)

**Rule:** As long as not engaged in economic protectionism (*per se* violation of the dormant commerce clause)may exercise authority so long as there’s a legitimate local purpose (balance with total interest involved with the degree of interference with interstate commerce)

**D:** Congress’s decision to not allow federal regulation of co-ops is field preemption, if the feds cannot regulate no one can

* 1. ^ Implications of the FPA
		1. Wholesale sales
			1. By IOUs and other private companies – rates subject to FERC regulation, question of how broad is preemption?
			2. By municipalities, states, and rural electric co-ops – states to regulatory power, some exercise this power, others allow boards/residents/members to make regulatory decisions
			3. Federal systems subject to federal regulation pursuant to enabling legislation
		2. Transmission – “wheeling,” before restructuring –
			1. Munis/co-ops would buy power from federal dams or other wholesale power producers
			2. IOUs would limit or deny access to the grid
			3. FERC had authority to order IOUs to open grid to transmission = “wheeling” power from non-IOU producer to non-IOU customer – under FPA § 205(b) no discrimination or unreasonable preference in service, facilities, etc.
1. Electricity Restructuring at the Federal Level
	1. The Move Toward Restructuring
		1. What is restructuring? – typical process/objectives
			1. Break up vertical monopolies so that generation becomes competitive – IOUs need to purchase electricity on the open market
			2. Allow the IOUs to continue to provide service to customers – although may let electricity sales to end users become competitive too = restructuring
			3. Ensure the transmission becomes open access – if the IOUs retain control over transmission, must have separation between sales and transmission = functional or actual unbundling
		2. Why restructure?
			1. Not all parts of electricity service are monopolistic
				1. Generation is competitive
				2. Electricity sales could be competitive
				3. Transmission? Until recently most people thought it isn’t competitive, innovation and technological changes may alter this
			2. Traditional regulation is not effective, or perhaps, not necessary
				1. Information asymmetries
				2. Ratemaking formula incentivizes wastes – rate base = profit based on keeping rate base large, operating expenses = test year methodology means no incentive to lower operating expenses
				3. Process is expensive and time-consuming
			3. Belief that market can do better
				1. Most states that restructured had high prices
				2. Other industries deregulated often yielding better prices
		3. Federal incentives promoting restructuring – PURPA, market rates, wheeling orders
	2. PURPA: The Accidental Impetus for Electricity Restructuring
		1. Major elements
			1. Promote different approach to rate design (no declining rates, yes time-of-day rates, etc.) – we’ve seen PURPA’s rate design elements already ^
			2. Promote development of qualifying facilities – avoided cost rates, interconnection requirements
		2. *Federal Energy Regulatory Commission v. Mississippi* (S. Ct., 1982)

**H:** Upholds Constitutionality (under Commerce Clause) of PURPA requiring states to implement rules requiring utilities (1) to purchase electricity from QFs, (2) to sell electricity to QFs, and (3) to connect QFs to the grid

**R:** Electricity is affecting interstate commerce and buying power across state lines, express preemption, and not overly intrusive simply opening the doors to the PUC

**Note:** Avoided cost rates (a type of wholesale rate) set by states per PURPA

* + - 1. PURPA § 210 – promotes QFs, requires purchase of electricity from QFs at ACRs, requires electric utilities sell electricity to QFs, requires electric utilities to connect to QFs, requires states to implement FERC’s rules
			2. PURPA § 210(f), Implementation of Rules – (1) after any rule is prescribed by the Commission, each state regulatory authority shall implement such rule (or revised rule) for each electric utility for which it has ratemaking authority
		1. *American Paper Institute, Inc. v. American Electric Power Service Corporation* (S. Ct., 1983)

**H:** Upholds two rules FERC promulgated pursuant to PURPA § 210 requiring utilities pay full avoided costs for electricity purchased from QFs and requiring utilities interconnect QFs

**R:** Not a big deal for ratepayers, setting a fixed rule is easier for FERC (may issue rules that override the adjudication requirements under the FPA), there are mitigating measures built into PURPA (waivers, contracts), and statute is not very clear and Congress wanted to support QFs

* + 1. Effects of PURPA on restructuring
			1. Avoided cost rule = cost incentive to build QFs – many long-term contracts signed, became problematic later when avoided costs fell as oil prices dropped
			2. About 1200 QFs came online – concentrated in California and New England, where ACRs were already high
			3. Demonstrated competitiveness in electricity sector
			4. Spurred calls for other rules for independent power producers (IPPs)
			5. Created framework for broader “wheeling” orders
			6. Gave states authority to set ACRs for QFs – ACRs = wholesale rates for QFs
			7. Practical implications (stay tuned) – QFs do better in states that like renewable power, may create room for states to develop feed-in tariffs (FITs), sort of
	1. Market Rates for Wholesale Electricity
		1. PURPA – QFs exempt from security laws (PUHCA) and ordinary ratemaking processes
		2. EPAct 1992 – Congress decided to set up new category of facilities, Exempt Wholesale Generators (EWGs) that were also exempt
		3. FERC movement to market rates
			1. Statutory standard = just and reasonable
			2. Rather than require ratemaking, FERC often uses market rates – set by contract (*Mobile Sierra*), set by trading mechanisms
			3. FERC’s goal – to ensure market is competitive – reporting requirements, no market manipulation
			4. Implications
				1. Market rates = presumed just and reasonable
				2. Contract rates – FERC cannot interfere unless “seriously harms the public interest” (*Mobile-Sierra* doctrine)
				3. Auctions – allow for spot market sales – peak/immediate energy demand
				4. But electricity needs to have real-time supply/demand match = risks in market dynamics
				5. For a market to work, need to get access to the grid, creates need for rules – open access, wheeling, grid management beyond specific IOUs
		4. Market Clearing Prices – the “uniform clearing price” auction
		5. Access to grid is essential for market performance (see next)
	2. Wheeling Orders and Transmission Coordination
		1. Transmission in wholesale competition – can’t buy and sell electricity if you don’t have a way to deliver it, IOUs owned the transmission systems and most generation = incentive to favor own power over competitors’ power, solution = “wheeling” orders
		2. Orders 888, 889, 2000
			1. Overall objectives – limit IOUs’ control over transmission to enable competitive wholesale market, prevent discrimination, avoid “takings” claims by allowing for recovery of stranded costs, i.e. costs incurred in reliance on expected continuation of monopoly system
			2. Conflicting goals – protect IOUs while creating competitive
		3. Overview and Stranded Costs
			1. *Transmission Access Policy Study Group v. Federal Energy Regulatory Commission* (D.C. Cir., 2000)

**I:** Who should pay stranded costs?

**H:** Upheld FERC’s rule that departing wholesale customers should pay stranded costs where had a reasonable expectation of continued service should pay

**R:** Struck a balance by allowing recovery of stranded costs but not all stranded costs and not all wholesale customers are going to have to pay just those departing for which the utility had a reasonable expectation of continued service, if wholesale customers don’t like the rules they can stay with the utility

**Rule:** Departing customer must pay amount it would have paid historic utility minus current market value of the power it would have bought for amount of time utility reasonably expected to provide service to that customer

Reasonable expectation of continued service – reliance solely on contract terms is not adequate measure when dealing with a regulated utility (implicit obligation to serve beyond contract terms), but utility had to pay attention to the proposed rule – investments after date of proposed rule are not stranded

* + - 1. Order 888, required utilities to –
				1. Functionally unbundle wholesale from transmission – create different business operations for wholesale sales and transmission, these must truly be separate to avoid gaming the system

File open access nondiscriminatory tariffs – state the terms of service (how much it will cost to transmit electricity along the system at certain times under certain parameters, e.g. firm service v. interruptible service), everyone is subject to the same rates and terms (except for stranded costs) for same types of service

Take transmission service for own new wholesale sales and purchases under same terms that they offer to others – no self-dealing

Develop and maintain same-time information system (OASIS) – meant to provide customers and IPPs with access to grid information to make sure they can deliver electricity when/where it’s needed, avoid congestion, ensure accountability

State separate rates for wholesale generation, transmission, ancillary services – separate rates prevent a utility from hiding its true rates and giving itself the advantage

Ancillary services – the electrical services necessary to ensure reliability, essential services

Spinning reserves – electricity immediately available to stabilize grid

Load management – prevent overheating and blackouts, send electricity where it needs to go to keep the balance, route electricity to its end destination

* + - * 1. This *does not* mean FERC is ordering restructuring, instead FERC is saying if utilities sell at wholesale, must separate wholesale from transmission, it is up to the state and utilities whether or not to buy and sell at wholesale (traditional procurement authority)
				2. On stranded costs – utility may recover costs from wholesale customers who use the utility’s service to purchase power from new suppliers and only if utility can prove it had a reasonable expectation of continued service to the switching customer

What stranded costs get covered under this rule? – Generation, deferred nonrecurring costs (meant to be recovered over a long period of time), nuclear decommissioning costs, etc. = potentially large amounts, could be hindrance for those states that want to restructure

* + 1. Jurisdiction
			1. *New York v. Federal Energy Regulatory Commission* (S. Ct., 2002)

**I:** (1) Does FERC have jurisdiction to regulate transmission in unbundled retail states? (2) Can FERC allow bundled retail to remain within state jurisdiction?

**H:** Upheld FERC’s assertion of jurisdiction in ordering wheeling and open access transmission lines (OAT), asserting jurisdiction over unbundled but not bundled transmission (state retains regulation)

* + 1. Who regulates after Order 888?
			1. Wholesale – split into sales and transmission (“unbundling”)
				1. Wholesale sales – market rates
				2. Wholesale transmission – order 888 – open access/non-discriminatory tariffs
			2. FERC regulates unbundled retail transmission, states regulate bundled retail transmission 
		2. RTOs, ISOs, and FERC’s Attempts to Establish Protocols for the Grid
1. State Restructuring: The General Model, the California Experience, and the Jurisdictional Impacts
	1. State Restructuring: The General Model
		1. Unbundling
			1. Functional – different programs for sales and transmission
			2. Actual – selling off facilities
			3. Jurisdictional implications
				1. Actual/functional unbundling = most generation now sold at wholesale = FERC
				2. Actual/functional retail unbundling = retail sales under state power

Retail choice for large customers – usually can just negotiate contracts with power producers

Residential customers – retail choice, utility stays provider, or new entities emerge; prices still subject to rate regulation

* + - * 1. But regulation of transmission is under FERC (Order 888, *NY v. FERC*)
		1. Establish entities to manage the market for electricity sales and the transmission system
			1. ISOs/RTOs
			2. Utilities continued to own the facilities and receive revenue from transmission
			3. But reliability, scheduling, ancillary services = ISOs
			4. FERC typically wouldn’t approve a restructuring plan if ISO/RTO not involved
		2. Allow end-users to pick choice of provider
			1. Generator choice – could pick source of electricity
				1. Same IOU
				2. Directing the IOU to purchase power from type of generator (e.g. green power) or to deliver power from a specific generator
				3. This is state restructuring that may create a competitive wholesale market
			2. Retail choice – can pick provider of retail energy and/or retail services
				1. Industrial users – might buy electricity directly from generator – retail wheeling
				2. Residential customers – could pick new service entity – less common and less effective
				3. This is state retail restructuring
		3. New rules for consumers sticking with the IOU, four options –
			1. Same IOU but new rates that pass through wholesale costs of electricity
			2. Some customers given new IOU (even if they aren’t choosing new IOU) = new service areas
			3. Same IOU but rates designed to transition to market-based prices and non-utility services (pass through + competition at retail over time)
			4. Utility delivers power, other companies can bid for right to serve customers
		4. Consumer rates protections – rate caps/reductions/freezes
			1. Often a combination – mandatory reduction + rate cap for period of time
			2. Meant to provide utilities guaranteed profit during transition, but limit extent of profit
			3. Expectation – when rate caps or freezes lifted, prices would be lower
		5. Exit fees/switching penalties
			1. Designed to limit frequent switching between service providers/power providers
			2. Might apply to 1st move or each move
		6. Stranded cost recovery
			1. Competition transition charge – all customers would pay until IOUs recovered
			2. Some states – only switching customers paid the costs (this is similar to what FERC did for wholesale)
		7. System benefit charges
			1. Many states had imposed new conservation/demand side management/efficiency requirements on utilities before restructuring
			2. Became additional fee in electricity bills
	1. State Experiences, major developments –
		1. Increased competition, but typically not at expected levels
		2. Wholesale power prices increased (expected to rise even further)
		3. Rate caps were scheduled to lift – rate increases often more than 50% higher than under caps
	2. California’s Experience
		1. The California Restructuring Plan
			1. Unbundling
				1. IOUs (3 in state) – had to divest/actually unbundle about half of their fossil fuel resources

Encouraged to divest more – lower rate of return on any fossil fuel plants they didn’t sell off

41% of utility-owned capacity sold, ⅓ of state total

* + - * 1. Generation – in hands of companies that bought the plants (paid $3.33B for plants with book value of $1.76B) = wholesale
				2. Retail – customers could pick their own providers
			1. Market manager/grid manager
				1. PX = market manager
				2. ISO = grid manager
				3. Basic interaction – PX negotiated day-ahead sales of electricity which then sent information about the sales to the ISO to manage/plan for the next day – same basic structure for hour-ahead sales
			2. Market rules re participation and sales
				1. IOUs had to go through the PX for all/almost all of their sales – limitations on long-term contracts
				2. PX would get bids from IOUs looking to buy electricity, e.g. we need X amount of power in X location at X time for $X
				3. PX would get bids from generators/power sellers looking to sell electricity
				4. Starting with lowest S amount, PX would fill IOUs’ orders, once orders filled PX would set the price (the market clear price (MCP)) at the highest level matching IOUs’ prices
				5. PX is managing this – sends a bill to IOUs once the MCP is set
				6. If IOUs don’t want to get billed, they don’t bid into the day-ahead (or hour-ahead) market or bid low prices

But they cannot enter into useful long-term contracts either

So where do they get their electricity? CalISO

* + - 1. ISO rules re reliability
				1. Managing the grid to make sure power delivery can happen
				2. Has authority to purchase electricity on its own to maintain reliability – if needs more power, will purchase it and then bill the PX which will then bill the IOUs
				3. Congestion avoidance – will pay generators who agree to curtail transmission to avoid congestion
			2. Stranded costs and rate freezes
				1. Stranded costs charges included in consumer bills
				2. Basic arrangement – consumers pay stranded costs but have set retail price for a period of time – this was the freeze
				3. Once stranded costs recovered, the rate freeze goes away

PG&E & Edison – longer time for rate freeze – when the market went crazy, they got stuck in the middle

SDG&E – had accelerated recovery plan, freeze had lifted and ratepayers got stuck with cost increases

* + - 1. Competitive transition charge
				1. Charge for new retail providers (competitors to IOUs at retail)
				2. Designed in part to compensate for stranded costs
				3. Made retail competition less likely
		1. What Happened?
			1. No problem for the first couple of year – people were bidding into the market at marginal cost rates (or close to it), lots of power to sell/low demand
			2. “Perfect storm” of events
				1. Low supply/high demand

Less hydro – hydro is a price mitigator

Less instate production (although plenty of capacity) – perhaps intentionally not happenstance

Less SW supply – growing desert communities

Hot summer/cold winter = high demand

Booming economy and population = high demand

* + - * 1. PX – day-ahead market/market clearing price – MCP under PX gets higher, collusion or just the market?

Bids go from $20-40 MWhr to $80-160 to above $500

Highest price = $3,800 MWhr

Once any actor started upbidding, they all did

Even those who didn’t intentionally manipulate had reason to like the system

* + - * 1. ISOs stopping bidding into PX because there’s a rate cap in the ISO – IOUs can’t do long-term contracts, so they just stop buying
				2. ISO – hour ahead/real time market

Must purchase power

If in-state power = rate cap

No more in-state power (re Enron)

So paying for out-of-state power = expensive

* + - * 1. ISO then bills the IOUs for out-of-state purchases
				2. Retail rate freeze = IOUs squeezed or ratepayers gouged – no way to recover for 2 IOUs (ratepayers not getting market signals), San Diego passing rates onto customers (rate freeze lifted) – big problem, but conservation incentive
		1. The potential for manipulation, California’s program
			1. PX – day ahead, market clearing price – if supply > demand no problem; if demand > supply then problem
			2. ISO – must buy obligation – limited authority
				1. Illegal rate cap on in-state power
				2. No rate cap on out-of-state power
			3. Retail price freeze = no demand response
			4. Actual unbundling
				1. Facilities sold to IPPs – wholesalers
				2. States lack power to regulate after unbundling
				3. FERC refused to regulate for awhile
				4. State can’t order suppliers to produce or sell more power
		2. Enron’s role in the California crisis
			1. Manipulating the market
			2. Taking advantage of PX/ISO dynamic = sell power for as much as possible for as much as possible on PX
				1. Bump up prices by telling generators to go out of service = altering supply/demand
				2. Schedule deliveries outside of California (counter to electricity demand) = create scarcity in the PX
				3. Some legitimate reasons for exporting power = long-term contracts available out-of-state
				4. Limits? California utilities quit purchasing through PX
			3. Taking advantage of PX/ISO dynamic = sell power back to California to outside the state; sell it back as out-of-state power
				1. Ricochet/megawatt laundering – withhold generation from in-state facilities, no ISO purchasing (ISO rate caps applied to in-state generation); ISO, acting in desperation, would buy the out-of-state power = no rate caps
			4. Transmission and ancillary services – fake schedules of load to earn congestions fees, fake sales of ancillary (standby) power, even though not standing by
		3. What ultimately ended the crisis?
			1. Retail rates increased significantly – lifting prices caps = some demand-side response
			2. FERC established regional rate caps
				1. ISO caps – $250/MWh, $500/MWh, $750/MWh – why did they go up?
				2. PX soft caps – $250/MWh then $150/MWh – applied to all wholesale power sales in western region, soft caps – sales above those rates would not set MCP
			3. New generation came on line (although there was likely always enough)
		4. The Aftermath of the California Crisis
			1. *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County* (S. Ct., 2008)

**F:** Tariffs in California = approval of the PX and CalISO system and rules and approval to participate and each sale of power in the spot market is a contract, no FERC review of contracts negotiated under these tariffs

**I:** (1) Does *Mobile-Sierra* presumption apply only “when FERC has had an initial opportunity to review a contract rate without the presumption? (2)Does presumption impose the same bar to challenges by purchasers as it does by seller?

**Rule:** *Mobile-Sierra* doctrine – rates set in a freely negotiated wholesale energy contract are presumed just and reasonable unless in violation of the public interest (FPA requirement); public interest test – may overcome presumption ^ only if FERC concludes that the contract seriously harms the public interest, i.e. impairs financial ability of utility to continue service, cast upon customers an excessive burden, unduly discriminatory

*Mobile-Sierra* – party to contract cannot unilaterally abrogate a contract by filing a new tariff, even if contract yields a less than fair return on invested capital parties cannot alter the contract by unilaterally asking FERC to approve a new rate

**H:** (1) Yes, it doesn’t matter when FERC review the contract, the nature of the contracting process is what matters (e.g. equal bargaining power, market dysfunction not necessarily relevant, can overturn contract rates only if they seriously harm the consuming public), (2) yes, applies to buyers and sellers – based on comparison to other rates set on marginal costs (not zone of reasonableness), if marginal costs are the touchstone, really just back to cost-based ratemaking

**J:** Remand because disparity between dysfunctional rates and the rates the customers could have paid in function markets could be an excessive burden and market manipulation could have altered the playing field *but* need causal connection before unlawful activity leads to contract invalidation

* + - 1. Tariffs v. contracts
				1. Before restructuring – tariffs = rates set by utilities subject to FERC approval, e.g. traditional ratemaking rates, Ks = whenever the parties negotiate
				2. After restructuring – tariffs = set overall rules of the game, Ks = negotiate actual prices and terms specific to the transaction (K rates can be quite variable for wholesale sales, less os for transmission)

Transmission tariffs – set the non-discriminatory rates and rules for transmission

Wholesale markets – the tariffs will function primarily as the rules for the market

* + - 1. What would make *Mobile-Sierra* inapplicable? If parties engaged in illegal action that cause the market dysfunction, not market dysfunction alone (why parties enter long-term contracts)
			2. After *Morgan Stanley*: *NRG Power Marketing v. Maine PUC* (Jan. 2010) – *Mobile-Sierra* doctrine also applies to 3rd parties not part of contract, “black box” settlement in *Morgan Stanley*
			3. Later cases – parties may include in contracts escape clauses from the “public interest” test and allow FERC to decide if rates are just and reasonable
			4. *Bonneville Power Admin. v. FERC* (3d Cir., 2005)

**F:** Per §§ 205 & 206 FERC may find rates no longer just and reasonable and order refunds (express authority for retroactive ratemaking) for public utilities (non-public entities not public entities)

**H:** FERC’s authority does not extend to non-public utilities, rejecting FERC’s argument that there’s no way to set rates and refunds that only apply to non-public utilities (instead is setting one rate of the market) and that when public entities subjected themselves to the market they subjected themselves to enforcement under those market rules (FERC isn’t resetting MCP, it’s ordering refunds)

**R:** Text of FPA is unambiguous on this

**Implication:** FERC could set market clearing price and bring contract claims against gov’t utilities as allegations arise under contract terms and new MCP demonstrates breach

**Subsequent:** Court of Federal Claims settled remainder as breach of contract and California collected most of its money

* + - 1. *MPS Merchant Services, Inc. v. FERC* (3d Cir., 2016)

**H:** FERC did find other companies engaging in similar illegal practices as Enron – false export (power sent out of state to avoid ISO price caps), false load scheduling (submitting false loads to ISO designed in part to secure real-time prices), anomalous bidding (bidding above marginal prices + other tariff violation, bidding so high either to effectively withhold power or to drive up MCP) – important because initially FERC found these actions legal and other markets have MCPs so sending a message to other MCPs that these actions are illegal

**Note:** No remedy ruling yet, may signal that if the west coast forms a regional market there will be more oversight

* + - 1. The Fallout: California –
				1. Suspended restructuring
				2. Allowed long-term contracts and utility ownership of generation assets
				3. More intensive utility regulation – decoupling (separating utility profits from sales), procurement rules (limited long-term contracts with coal, policies to promote renewable power), efficiency mandates
				4. But ISO still manages transmission and a short-term wholesale market
				5. And ongoing discussions about creating a west-wide RTO
		1. Managing the Grid: RTOs and ISOs Overview
			1. Basic Issues
				1. If the IOUs run their own grids and retain control over bundled retail transmission, doesn’t that create opportunities for discrimination?
				2. Even absent discrimination, the influx of new IPPs into the transmission system cries out for better management of the transmission grid – many disparate sources, increased peak power demand, need for scheduling, etc.
			2. ISOs – independent system operators – authority over the grid’s management, no ownership of the infrastructure, can be state-specific or regional
				1. Rules – structure

Independent of individual market participants – no control over the decision-making process

No financial interest in the economic performance of any power market participant

* + - * 1. Rules – open access and reliability

Single, non-pancaked rates/non-discriminatory

Pancaked rates = charging access fee to each different system – hurts long-distance transmission and more remote generators

Scheduling done by ISO

ISO oversees maintenance and reliability

Should have control over interconnected transmission facilities

Constraint identification and relief (through trading, etc.)

* + - * 1. Rules – management rules

Efficiency incentives

Transmission operations ahead of the curve

Publicly available information

Work for other ISOs

* + - 1. RTOs – regional transmission operators – authority over grid’s management, no ownership of infrastructure, regional management, an ISO can qualify as an RTO
				1. Voluntary order 2000 – some areas have embraced RTOs and regional planning, others have not
				2. Main elements

Indepedence

Scope – regional/enough to operate reliably and effectively

Needs authority over the system

Short-term reliability

Tariff administration and design

Congestion management

Parallel path flows

Ancillary services

OASIS

Market monitoring

Planning/expansion

Interregional coordination

* + - 1. v. Transcos – some advocates want companies (either for-profit or non-profit) to buy up the transmission system and run it as a separate enterprise = the model in the UK but ownership transferred from government to private company (National Grid)
			2. No RTO? Balancing authorities and OATTs
	1. Electricity Restructuring in Other Markets
		1. PJM Markets
			1. PJM interconnection = RTO approved to manage transmission system and wholesale market
			2. Transmission – “air traffic control” – day to day transmission and reliability
			3. Markets – energy and capacity
				1. Energy market

Generators sell to PJM sells to LSEs (load-serving entities)

Day-ahead and real-time (hour-ahead)

Market clearing price

LMP (locational marginal pricing)

Generator’s ability to actually deliver electricity to load depends on congestion

If power cannot actually reach the loa, then should not be included in auction

Will drive up MCP at that location and create a price signal to invest

E.g. LMP policy intersection with MCP – no sale for D because congestion makes power non-dispatchable

* + - * 1. Capacity Market

PJM bids to buy capacity at location and certain prices – price caps set under Reliability Pricing Model; three years in advance

Generators bid to sell capacity = promise to keep power available

Generators get fixed payments for fixed period of time

PJM can then call on generators to deliver power on demand – will usually also pay for the actual energy

2006 Rules – price ceiling; price floors (minimum offer price rule (MOPR)) – applied to new generators, exemptions (renewables can bid below MOPR or bid at zero and be “price takers”, state mandated generators can also bid at zero, LSEs may self-supply or enter into bilateral contracts and buy and sell excess in capacity markets); new entry price adjustment (NEPA) – fixed price for 3 years, based on idea that new load growth would enable them to stabilize after 3 years

2011 Rules – rid of state-mandated generators exemption and LSEs’ ability to buy and sell excess in capacity markets

Price floors – keeps prices up and attracts new capacity but if exemption, allowed to bid below floor – lowers MCP and distorts incentives for new generation 

* + - * 1. PJM Capacity and Energy Markets – expected economic signals from these systems?

LMP – Energy Markets – encourages generators to locate where they will receive higher prices, encourages large users to locate where they can buy low-cost power, encourages construction of transmission lines in congested areas

Capacity market – long-term price signal to build new plants

* + - * 1. PJM Capacity and Energy Markets – actual economic signals from these systems (at least according to Maryland)

Inadequate incentive for new power or capacity because the system pays higher than average prices to incumbents

Incumbents benefitting from congested systems that will not build new plants and lower prices

Plants built in congestion zone might face curtailment under LMP = no sales = no incentive to risk new construction

RPM and NEPA not working for capacity market – 3-year contract under NEPA is too short, price signals not sufficient

* + 1. Competitive Markets: Jurisdictional Implications
		2. Capacity Auctions
			1. *Hughes v. Talen Energy Marketing, LLC* (S. Ct., 2016)

**H:** Invalidated Maryland’s contract for differences to make up for FERC’s elimination of its price floor exemption because the state is participating in the wholesale market by indirectly setting wholesale market rates and it’s preempted from doing this

**Contract for differences** – utilities enter contract with new generator for set price and generator sells power/capacity into markets with contract as backup, if market price > K price, generator pays utilities, if K price > market price, utilities pay generators

**Price Floor exemption** – new generators are not exempt from the price floor

**Limits:** Ruling limited to here because state is disregardingan interstate wholesale rate required by FERC, explicitly says does not address the permissibility of other measures the state might employ to encourage development of new or clear generation, including tax incentives, land grants, direct subsidies, construction of state-owned generating facilities, or re-regulation of the energy sector

* + 1. Demand Response Regulation in Wholesale Markets
			1. Demand response – programs to encourage end users to curtail energy use during peak periods or to protect reliability
				1. Peak prices – retail customers respond to high rates by lowering use
				2. Load reduction payments – retail customers agree to reduce consumption in exchange for payment, e.g. industrial customer with own power supply
				3. Technological: Batteries, self-supply
				4. Behavioral/motivational
			2. Traditionally treated as a retail enterprise *but* EPAct 2005, Order 719, Order 745
				1. EPAct 2005 – policy to encourage demand response and to eliminate barriers to demand response in energy, capacity, and ancillary service markets

Energy – actual power production

Capacity – ability to produce (available power supply)

Ancillary – everything else to ensure grid reliability, e.g. storage, spinning reserves, load shedding

* + - * 1. Order 719 – RTOs and ISOs must provide 3rd party aggregators of retail customers (ARCs) access to the wholesale market, except where state regulations affecting retail utility prohibit; how does wholesale market access work for demand response? –

Demand response aggregators agree to bid “negawatts” into the wholesale market – aggregators have contracts with demand-side entities who receive compensation for curtailing power demand

RTOs will then either purchase power or purchase “negawatts”

Why would state regulators prohibit demand response participation in wholesale market? – stranded costs, utility planning, and rate design

Bundled utilities make investment decisions based on demand forecasts (expected power sales)

If retail sales drop substantially below forecasts, utilities may have too much power generation they cannot sell

If demand response works too well, some generation assets must be “stranded” and retail prices may increase for other customers

* + - * 1. Order 745 – requires utilities (“load-serving entities”) to pay locational marginal prices (LMPs) for demand response
			1. PJM implementing Order 719
				1. ARC applies to participate and identifies customers it represents
				2. PJM will notify appropriate utilities (LSEs)
				3. Utility will have 10 business days to object on grounds that a customer is not eligible to participate
				4. If objection is untimely or inadequately supported, PJM will assume state law does not prohibit
			2. *Indiana Utility Regulatory Commission v. FERC* (D.C. Cir., 2012)

**I:** Challenges PJM’s implementation of Order 719 ^ as enjoining retail customers from participating in wholesale demand response program without prior approval and PJM’s proposed tariff as (1) directly interfering with state jurisdiction over retail sales and (2) ARC, not the utility, should have responsibility to certify eligibility

**H:** (1) Not adequately raised administratively so IURC loses and (2) IURC loses (FERC wins) because A&C review is deferential and FERC adequately explained its reasoning

* + - 1. *FERC v. Electric Power Supply Ass’n* (S. Ct., 2016)

**I:** Challenges Order 745 as an impermissible intrusion into retail market and that LMP rates are too high

**FERC:** At the confluence of state and federal jurisdiction but because demand response directly affects wholesale rates, FERC has jurisdiction

**H:** (1) Not merely an issue of whether it will affect retail rates (admits here it does) because every wholesale rate does, rather it’s an issue of whether it will affect wholesale market and here, everything is happening in the wholesale market; (2) no, should not have lowered their DR rates to account for the retail savings would defeat w/s DR market



# Renewable Power

1. Overview of Renewable Energy Sources
	1. Wind Power
	2. Solar Power
	3. Hydropower
		1. Run of the river hydro – diversion that doesn’t block the river entirely
		2. Pumped hydro storage
	4. Biomass
	5. Geothermal
2. Distributed Generation
3. What is the future of renewable energy?
	1. Prices – wind power is often competitive with coal and natural gas (coal is cheapest), bt most renewables are expensive (but prices dropping)
	2. Subsidies expire, then don’t
	3. Capacity – location and generational potential
		1. Solar capacity – 100x current and future consumption (100 sq miles could power entire US)
		2. Wind capacity (onshore) – approx. 16x current consumption
	4. Demand affected by policy changes
4. Renewable Portfolio Standards
	1. An Overview of Renewable Portfolio Standards and Renewable Energy Credits
		1. State mandates for utilities to obtain certain percentages of electricity from renewable sources by specified dates
		2. Definition of renewables is a matter of state law – wind, solar, biomass are usually included but e.g. in PA waste coal is included
		3. Carve-outs – require utilities to obtain certain amount of specific energy type or size, e.g. 10% from solar, 5% from distributed generation
		4. Renewable Energy Credits (RECs)
			1. Represent the “greenness” of the electricity resource, e.g. show that 1 kWh of electricity is a qualifying type of renewable electricity
			2. May be bundled or unbundled
				1. Bundled

Accounting and tracking tool – REC ID stays with the resources through all the trades, helps ensure facilities aren’t making up RECs or double-counting

Accompany the electricity itself

Means an entity cannot transfer the REC without actually also delivering electricity

E.g. REC # 003-001-121010-105 – translates to facility ID # - type of power - date of generation - unit ID #

* + - * 1. Unbundled

Accounting/tracking mechanism – tracking applies to the RECs, electricity is sold as a separate commodity and generally it doesn’t matter what happens to the actual electricity

Tradeable instrument, trading –

Fully unbundled = generators/utilities may sell RECs independent of electricity

Why allow trading? – Limited local sources, allows optimal placement of generators, monetize environmental benefits

 Why not allow trading? – Benefits accrue to other states at expense of ratepayers (jobs/environmental benefits), environmental justice, marketplace concerns (pricing, compliance, banking, etc.), different rules in different states = complications

* + - * 1. Other REC features

Carve-outs for certain types/sizes of energy, e.g. distributed generation

Multipliers – different values for different resources, e.g. each MWh of solar is 3 RECs, wind is 2 RECs, biomass is 1 REC

Risks? Trading, actually devalues renewables to certain degree because if RECs measure compliance and each MWh of wind is 3 RECs only need ⅓ of the wind power

Enhanced REC values for proximity to consumption site or in-state production – clear dormant commerce clause violation for in-state production treatment, dormant commerce clause concerns based on proximity

Lifespan of RECs

Should they expire after a set time? If so will have less value but will incentivize continued renewable energy generation (and increased generation as RPSs get more stringent)

Should utilities be allowed to bank them indefinitely? If so, will make future compliance cheaper even as RPS mandates increase, may incentivize buying spree early on (when RECs are presumably cheap because mandates are low) so will promote early renewable development but too much banking = reduced incentives in the future

* 1. RECs, Ratemaking Proceedings, and Contracts
		1. RECs and ratemaking
			1. Fuel adjustment clauses – allows utilities to pass costs of fuel onto ratepayers without going through full ratemaking proceedings, can utilities pass unbundled RECs onto ratepayers through the fuel adjustment clause? (New Mexico – no, RECs are not fuel)
		2. RECs and contracts – who owns the RECs if the contracts don’t specify? Applies to long-term contracts entered into before states passed RPSs, if states didn’t specify ownership what do the contracts require?
		3. *ARIPPA v. Pennsylvania Public Utility Commission* (2d Cir., 2009)

**H:** For contracts entered into prior to development of an RPS (for which contracts don’t specify unbundled REC ownership) utilities (distribution companies (PA restructured)) own the RECs because either option creates a windfall and it’s fairer to ratepayers that it falls onto the utilities; state is not preempted, FERC made clear that RECs are outside of PURPA’s scope so this issue is one of state law

1. Federal Tax Credits
	1. Phases of Renewable Energy Project Development
		1. Figure out where the good wind is
		2. Get the land = lease agreement – money and time
		3. Get permits = land use/siting/etc. – money and time
		4. Buy the turbines – money
		5. Build the project – money and time
		6. Connect to the grid – need interconnection agreement – money and time
		7. Produce power and sell it – ideally they want a long-term contract (Power Purchase Agreement (PPA))
	2. The PTC and the ITC Briefly Explained
		1. Investment Tax Credit (ITC) – tax credit based on cost of renewable energy projects
			1. Tax credit based on cost of renewable energy projects
			2. Credit varies for type of project (solar, small wind (turbines of 100 kW or less), and converted PTC = 30%, geothermal = 10%
			3. Before extenders facilities must be placed in service by 12/31/16 – residential tax credit will expire, commercial tax credit will drop to 10%
			4. After extenders credit drops beginning in 2019, ultimately down to 10%
		2. Production Tax Credit (PTC) – tax credit based on amount of renewable energy produced
			1. Covers wind, biomass, geothermal, small irrigation power, municipal solid waste (landfill gas), some hydropower (new and improved), and hydrokinetic
			2. Amount – 1.5 cents/kWh adjusted by inflation (for wind, geothermal, and closed-loop biomass), today’s value is 2.3 cents/kWh (or $23/MWh); .75 cents/kWh for others
			3. Equity investors
				1. Need a taxpayer to take advantage of the credit
				2. Equity investors = funders, become “owners” of the facilities for life of the credit
				3. Necessary because many renewable energy developers do not have tax liability 
			4. Risks of equity investors – capital market influence, marginal wholesale market costs, PTC boom/bust
			5. Lifespan of credit (PTC) = 10 years after ~~placed into service~~ (now) begin construction = sign PPA and spend 5% of total project value
	3. Sunsets/eligibility dates
		1. ITC – phase down at various dates
		2. PTC – varying dates and requirements
			1. Placed into service became “begin construction” ^
			2. IRS guidelines – begin construction = commence physical work of a significant nature, safe harbor = pay or incur at least 5% of project cost + significant efforts to advance toward completion of a project
			3. Phase-down – full credit if begin construction by 12/31/16, 20% drop each year after
		3. Why sunset? 
			1. Originated out of the idea that every agency should have to re-justify its experience every 5-10 years
			2. Designed to increase oversight and maintain relevant policies
			3. Transferred mostly to tax policy – now it’s an accounting tool/trick, federal budget projections last 10 years and sunsets help things look better than they might actually be
			4. Supposed to spur investment – idea that companies will invest quickly to take advantage of the available credits
		4. Why not sunset?
			1. Lobbying, special interests, etc.
			2. Gaps in tax credits increase uncertainty
			3. Spurred investment drives up prices – the suppliers know about the credits, too, and know that there’ll be a spike in demand
			4. Wasted time on paperwork and lobbying that could be better spent in development
2. Net Metering
	1. Net Metering Explained
		1. Effectively allows small generators (including residential customers with solar arrays) to run the meter backwards – may have net retail, net zero, or net wholesale
		2. E.g. if a customer uses 1,000 kWh of electricity from utility but delivers 500 kWh of electricity back to the utility, consumer would only have to pay for 500 kWh
		3. Different models
			1. Allows customer to fully net out costs of electricity from utility (customer pays $0)
			2. Limit amount of electricity customer can net out
			3. Allow customer to earn a profit if customer produces more than customer consumes
		4. Issues
			1. How does net metering affect federal/state jurisdiction?
			2. How much must the utility pay for consumer-produced electricity?
			3. Political: Utilities and others oppose
		5. Limits
			1. Most states limit the size of the facilities that can qualify – may also limit who can participate, e.g. homeowners only
			2. Many prohibit homeowners from earning revenue, i.e. homeowner can zero out bill but not sell excess at wholesale
			3. Is net metering good for distributed generation?
				1. Requires high upfront investment, too high for most homeowners
				2. Or requires entity willing to invest in smaller disperse projects – solar leasing model by Solarcity
				3. Payback period typically quite long, absent federal or state incentives
				4. Does not compensate utility for grid management – offsetting production at retail rates = no recovery for utilities for services
		6. Net metering and the death spiral
			1. Customers with high rates will benefit most from net metering, also are the customers with greatest ability to afford own solar arrays
			2. Utilities still must pay fixed costs incurred before net metering, prices will go up for remaining customers
			3. Other customers will participate
	2. Net Metering and the Federal Power Act
		1. If utility sales to homeowner ≥ homeowner sales to utility – net retail transaction, homeowner will receive discount on amount of power sent to utility, basically meaning homeowner is selling its power at retail rates
		2. If utility sales to homeowner < homeowner sales to utility – net wholesale transaction, homeowner will receive retail discount on amount of power sent to utility, basically meaning homeowner is selling its power at retail rates until its sale exceed utility’s sales
		3. If utility sales to homeowner < homeowner sales to utility – QF involved – net wholesale transaction, rates under PURPA (ACRs)
		4. *In re: MidAmerican Energy Company* (FERC, 2001)

**I:** (1) Is net metering preempted? (2) What limits exist on rates the utility must charge/pay? (3) What is an acceptable time frame?

**H:** (1) No, this is about measurement, no requirement under FPA that every flow of power is a sale, ok for states to net out before reaching the question of how much utilities owe; (2) once it’s netted out, if it’s a net purchase from the utility then the homeowner pays retail rates for the remainder, if it’s a net sale to the utility then the utility pays retail rates up to zeroing out then wholesale rates set by FERC for any excess (note, if generator is a QF then the rates are ACRs); (3) hourly ok, monthly ok, yearly? – many states have a yearly program, FERC hasn’t said it’s not ok so seems to have implicitly blessed

1. Feed-In Tariffs and PURPA
	1. FITs Explained
		1. Provide a guaranteed rate of return for anyone who delivers qualifying types/amounts of electricity to the grid
		2. Usually limited to cogeneration/renewables and certain sizes (at least in the US)
		3. Dominant method for promoting renewable energy in Europe
		4. How structured
			1. Usually long term power purchase agreements (PPAs), like under PURPA, where utility must buy certain amount of electricity from qualifying producers
			2. Guarantee access to the grid
			3. Incentive payment structures (cost of renewable energy generation + a rate of return)
		5. Payment options
			1. Levelized cost of renewable energy generation + guaranteed rate of return
				1. Levelized costs = what generator needs to break even; capital costs, operating costs, fuel costs, etc.
				2. Rate of return = the profit on investment – based on costs/income to the generator, not avoided costs of the utility
			2. Value-based costs
				1. Value to society = reverse of externalities
				2. Value to utility = avoided costs/time and location values, e.g. peak energy supply
			3. Fixed-price incentives
				1. Regulators just set the price earned per kWh regardless of market prices or specific facility costs, e.g. all qualifying renewables earn $.10/kWh
				2. Most common approach worldwide
			4. Premium-price payments
				1. Added value to spot electricity price to ensure generators get adequate return
				2. Constant = per kWh additional payment, regardless of market price, e.g. $.02/kWh, this is basically how the PTC works except the utility pays
				3. Sliding = additional payment that will phase out as market prices climb, but ensure guaranteed minimum rate of recovery – this is illegal under *Talen v. Hughes*
			5. Auction-based system
				1. Becoming more common
				2. Idea is that utilities will bid for electricity produced from renewable sources
				3. Highest bid wins
				4. Need scarcity for rates to be competitive
	2. US Feed-In Tariffs Legal Basis

|  |  |
| --- | --- |
| **FITs** | **PURPA** |
| Must buy power | Must buy power |
| Must connect to grid | Must connect to grid |
| Incentive rates – what independent facilities need | Avoided cost rates – what utilities would otherwise pay |

* 1. Feed-In Tariffs and Federal Preemption
		1. PURPA avoided cost regulations, factors –
			1. Data re utility’s cost structure/plans to add capacity, i.e. ability to generate electricity at certain point in time
			2. Availability of capacity or energy from a QF during daily and seasonable peak periods
				1. Ability of the utility to dispatch the QF
				2. Reliability of the QF
				3. Contract terms
				4. Extent to which scheduled outages of the QF can be coordinated with scheduled outages of the utility’s facilities
				5. Usefulness of energy and capacity supplied from QF on the electric utility’s system
				6. Smaller capacity increments and shorter lead times available with additions of capacity from QFs
			3. Relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use
			4. The costs or savings resulting in line losses from those that would have existed absent QF purchases
		2. *In re: California Public Utilities Comm’n Order on Petitions for Declaratory Order* (FERC, 2010)

**I:** Challenge to California’s Waste Heat and Carbon Emissions Reductions Act as preempted feed-in tariff – if not QF, FERC governs, if QF PURPA ACR governs

**H/R:** Invalidated, doesn’t matter that it’s called and “offer,” FIT setting wholesale rates so either FERC or PURPA ACR governs, states still have authority over procurement and may order the utilities to get their energy from certain sources but may not set wholesale rates (unless PURPA and then must be set no higher than ACRs) and policy rationale (environmental policy) cannot change this dynamic; preemption does not apply to public agency sellers (e.g. municipalities) and they may voluntarily establish FIT whereby the agree to pay extra amounts for the power they purchase (essentially a market participant exception); distribution level facilities are a wholesale sale, although distribution is not regulation these are sales and thus distribution is not even implicated

* + 1. *In re: California Public Utilities Comm’n Order Granting Clarification and Dismissing Rehearing* (FERC, 2010)

 **I:** Are ACRs flexible enough to authorize some types of FITs?

**H:** Long term v. short term – states may consider long-term costs, don’t need to pick the lowest possible ACRs, multitiered is ok; states may determine that capacity (not just actual energy) is being avoided and may rely on cost of avoided capacity to determined ACRs (capacity = ability to generate electricity at a certain point in time); ok if procurement rules make some sources ineligible – CA won’t consider costs of coal or natural gas in determining avoided costs because they don’t qualify under CA’s long-term procurement plan, state laws governing eligible resources will matter a lot; adder/bonus to reflect avoided transmission/distribution upgrades not ok if above avoided cost but if environmental/other costs are real costs incurred by utilities then may be a part of avoided costs (i.e. if PUC decides connection to a QF will enable utility to avoid upgrades to transmission/distribution system then may include in avoided costs; if can’t show there are other ways to compensate for externalities, e.g. RECs)

**Takeaway:** ACRs may become playing field, may work in tandem with RPSs to drive up payments for renewables

# Transmission

1. Background: The U.S. Electric Grid – timing, access (congestion, interconnection, planning), costs, storage, other strategies
	1. Transmission timeline
		1. 1978 – PURPA – interconnection mandate as part of purchase mandate
		2. 1992 – EPAct 1992 (EWGs), PTC
		3. 1994 – first RPS, many others followed
		4. 2001-2011 – wind growth 1500%
		5. 2010-2014 – solar growth 418%
		6. Existing infrastructure
			1. Most of the transmission system was built in 1950s and 1960s to serve central power stations
			2. Many optimal utility-scale renewable energy sites are located away from existing transmission infrastructure – demand in urban areas for rural RE production, siting of RE driven by transmission access
		7. Today – solutions that go beyond transmission build-out
	2. Access issues
		1. No transmission in some areas
		2. Congestion – inadequate access on line into key consumption areas (urban cities, esp. on the East Coast), curtailment strategies than can result in sources getting dumped
		3. Interconnection – direct discrimination prohibited but still allegedly an issue, open access transmission tariffs (OATTs) designed for baseload and peak plants, not intermittent generators
		4. Planning – lack of planning = good opportunity for implicit discrimination
	3. Costs
		1. Independent generators must not only pay to access the grid, but must also often construct own interconnection lines
		2. Until recently, were required to pay for power in 1-hour firm intervals, even though they did not use them – could also face fines if did not use their full intervals
		3. Could also face higher costs associated with reliability (or at least earn less if not able to supply firm power)
	4. Storage
		1. Lack of storage makes electricity system vulnerable to market manipulation
		2. Lack of storage makes supply and demand dynamic precarious
		3. Lack of storage may undermine some RE sources that may produce at low-demand times
	5. Planning and policy design
		1. Central power station model – build 1 plant, 1 line, good to go
		2. RE policy – build as much as possible following economic incentives and mandates, wherever transmission access is best or most valuable, e.g. California market access
		3. Intentional transmission line construction highly contested
		4. RE development often seen as a problem, today become more of a solution
	6. Remedies
		1. Strategic development of transmission lines
		2. Focus on distributed generation as balancing strategy
		3. Storage
		4. Strategic energy planning
2. Federal Preemption of State Siting?
	1. 2005 EPAct, FPA § 216
		1. First significant foray into state siting decisions of transmissions lines
		2. v. Natural Gas Act § 7 – FERC has exclusive pipeline siting power, once it approves development of the line, gas companies get the power of eminent domain
		3. FPA § 216 – odd language and tenuous power
			1. (a) Designation of NIETCs by DOE
				1. Study transmission congestion with affected states
				2. Designate areas with transmission capacity constraints or congestion that adversely affects consumers as National Interest Electric Transmission Corridor (NIETC)

Whether lack of adequate or reasonably priced electricity affects economic viability or end markets

Whether growth/end markets jeopardized by reliance on limited sources and diversification of supply is necessary

Would serve energy independence

Would be in interest of national energy policy

Would enhance national defense/security

* + - * 1. 2007 – Mid-Atlantic corridor and southwestern US corridor designated
			1. (b) & (c) FERC-issued construction permits
				1. (b) FERC-issued construction permits – FERC may preempt state siting process if state doesn’t have authority to approve siting, consider interstate benefits; applicant cannot apply for permit because it doesn’t serve end users in the state; state has authority but withholds approval for more than 1 year after application/NIETC design; or conditions approval in such a way that the line will not significantly reduce congestion or is not economically feasible
				2. (c) FERC-issued construction permits – FERC reasons for permit – national security, energy independence, relieve congestion (what about adequate capacity?), economic growth, benefits to end users
			2. (e) & (f) federal eminent domain authority – if FERC issues a permit, the applicant gets the right of eminent domain – should try to negotiate a contract, if it can’t get a contract it may get court order to condemn land, must pay compensation (fair market value)
			3. (i) interstate compacts – Congressional consent (required under Constitution), if 3 or more states enter into compact then FERC has no permitting authority unless the parties are in disagreement (need unanimous approval/disapproval) then apply requirements (re withholding for more than 1 year, unreasonable conditions)
	1. *Piedmont Environmental Council v. FERC* (3d Cir., 2009)

**I:** FERC regulation implementing § 216 regarding when FERC may preempt state siting (“withheld approval for more than one year” = permit denial within one year (FERC rule))

**H:** Invalidated – means hold back/keep from action continuously, cannot include finite act of denial (withhold ≠ denial); the overarching purpose is limited preemption under specific circumstances (e.g. lack of state auth to consider interstate benefits or for applicant to apply, inapropriate state action including project-killing conditions in approved permit, or inappropriate state delay), state may deny a permit based on traditional state considerations (e.g. cost and benefit, land use and environmental concerns, health and safety), FERC override meant to defeat inappropriate action only not to supplant appropriate state action

**D:** Context suggests Congress intended to prevent states from frustrating the goal of reducing transmission congestion (ability to override certain approvals shows Congress’s willingness to trump state decisions), override not limited to only those scenarios in which a state has acted with transparently deceptive practices

**Implications:** Majority’s reading controls, states may deny permit applications under legitimate grounds

* 1. *CWC v. DOE*
		1. DOE “in consultation with affected states shall conduct a study”
		2. After considering alternatives and recommendations from interested parties (including opportunity for comment from affected states) DOE shall issue report based on study which may designate NIETCs
		3. Invalidated NIETC designations for inadequate consultation
	2. Round Two – DOE prepared second draft study with consultation, decided to not designate any NIETCs
	3. Questions – what role should the federal gov’t play? Is it time for a national grid? What are the risks and benefits of local preemption?
1. Transmission Cost Allocation
	1. Some states have entered into RTOs – means in part that the RTOs decide when new lines get built, these lines are going to be used for unbundled wholesale transmission among other things so FERC decides who pays for what, how should it divide the costs?
	2. *Illinois Commerce Commission v. Federal Energy Regulatory Commission* (3d Cir., 2009)

**H:** (1) Upheld FERC’s rejection of recovery of sunk and marginal costs of existing transmission line because can’t double-recover where already paid for/not fully depreciated so going to recovery in full and not entitled to additional recovery; (2) invalidated FERC’s pro rata plan (raised uniform amount to defray facilities’ costs) for financing new high-capacity transmission lines because offered a poor cost-benefit analysis – must show articulable and plausible reason to believe benefits are roughly commensurate with the costs and offer factual support

**D** (Cudahy): Transmission is a backboneinfrastructure problem and FERC should be able to do something about that without fighting intermediate states

 **Takeaway:** If going to try and assign costs for new transmission lines, need some sort of cost analysis

* 1. *Illinois Commerce Comm’n v. FERC* (3d Cir., 2013)

**F:** Cost allocation of MISO’s multi-value projects (MVPs) (high voltage lines to bring power from wind-rich great plains to urban areas) – cost allocation based on wholesale consumption not proximity or peak power

**H:** Rejects Michigan’s argument – the whole point of this plan is to make access easier/cheaper for generators and wholesale buyers are going to get cheaper power in the end; ok for departers fo leave MISO but if MISO invested in MVPs before the departers announced their plans to go departers may have to pay some of the costs (alike stranded cost orders)

**R:** Data available to show benefits to all, just said need rough proportionality (and they have much more info at least), scope of benefits much broader (e.g. less pollution), Michigan’s argument is unconstitutional, or based on an unconstitutional RPS

1. FERC Order No. 1000
	1. Planning reform
		1. Utility transmission providers must participate in regional planning process
		2. Must consider transmission needs driven by public policy requirements and develop solutions to address those needs
		3. Must coordinate with neighboring regions
	2. Cost allocation reform
		1. Each public utility transmission provider must participate in regional planning process that has regional cost allocation method for new transmission facilities – subject to six principles
		2. Neighboring regions must have common interregional cost allocation method for new interregional facilities
		3. Participant-funding of new transmission facilities is ok, but cannot be the cost allocation method, i.e. cannot just say participants must pay
	3. Non-incumbent developer reform
		1. Are “merchant” transmission owners, like IPPs, only independent transmission line builders
		2. Remove federal right of first refusal for a transmission facility selected in a regional transmission facility selected in regional transmission plan for cost allocation purposes
			1. Federal right of first refusal – incumbent utilities have first right to build new transmission lines, now they don’t
			2. Will allow competitive bidding to build new lines
			3. Does not affect siting
	4. Order 1000 Implementation
		1. Multiple rounds of compliance plans from different regional transmission entities + FERC review (2013-2016)
		2. Implementation really just beginning, initial take not likely to overcome some of the major hurdles to transmission line development
	5. Western RTO
		1. Energy imbalance market – spot market in California expanded to other actors outside of California
		2. Some thoughts about creating western RTO
			1. Major impediments – California fears loss of autonomy, some in California fear too much coal-based power will enter into their states
			2. Why do it? Likely an efficient way to bring way more RE online
	6. Storage and Transmission
		1. Most states energy experts think storage plus smarter transmission planning are necessary
			1. FERC has issued rules regarding cost recovery for storage
			2. California has ordered its utilities to procure storage
			3. Increased storage capacity may enable growth of renewables and more distributed generation

# What’s Next for Electricity?

1. Rate Design Wars
	1. Zucchini for zucchini? No, because inclining block rates (“increasing block pricing”) and solar prices dropping even without inclining block rates
	2. Fixed costs? For past mistakes, for legitimate fixed costs, question is what about future “mistakes?”
	3. Options – fixed charges (customer charge) separate from energy charges (based on amount of consumption), meaning energy charges are lower for those who consume less and fixed charges are set on a per customer category within classes
		1. Cons: Weakens price signal to conserve (will still pay fixed costs), will lower net metering return
2. Energy Justice Issues – does net metering hurt low income customers?
	1. Florida – NAACP opposition based on fear of getting stranded and based on concerns of lower income customers subsidizing wealthier ones who can afford installing solar
	2. Indiana – NAACP support based on environmental justice and economic opportunity
	3. LA – Presente support for California’s policies
3. Common Confusion
	1. How to figure out costs?
		1. E.g. NEM cost shift – idea that NEM customers do not pay enough of fixed costs and those will shift to other customers
		2. NEM adding present value? Idea that NEM customers are providing power that utilities might otherwise have to produce/procure during peak periods
		3. NEM customers paying full share? Idea is that NEM customers are paying what they should, but not more (but they were paying more before)
	2. NEM for other changes
		1. Should customers who drastically reduce consumption pay more because they become more efficient?
		2. If customers use batteries to store power when it’s cheap, should they pay more because they consume less higher-priced peak power?
		3. Why single out NEM?
4. Wisconsin’s Approach
	1. Increased fixed charges on all residential bills from $9 to $16 fixed charges, lower energy charges
	2. Will drop NEM payments from $.14/kWh to $.03/kWh
	3. Additional fee for using solar rays
5. Florida Vote – Constitutional amendment that seemed pro-solar but would really allow increased prices on solar arrays failed
6. Nevada Vote – ballot measure succeeded but other hurdles (e.g. major increase for fixed charges for solar customers)
	1. Should customers have choice where they buy their power? Big support from large customers, will it hurt smaller/lower income customers?