Costs

Developing the language of costs
Objective

• Develop a common language for talking about costs
  • The big four:
    • Capital cost
    • Operation & Maintenance costs (cost of keeping the plant open)
    • Average cost (cost per MWh produced)
    • Variable (marginal) cost

• Show how costs depend on plant type and capacity utilization
Fixed cost [FC]

- Capital cost of *building and financing* a plant
  - Cost of construction
  - Payment to the owners of capital (interest rate)
  - Amortized loan amount over term of loan
- We will report this as a monthly cost
  - *Constant over the life of the plant*
  - In theory, this is the monthly rental price of capital
- We need to know three things
  - Amount of capital investment
  - Term of the loan
  - Interest rate: return on the investment (or interest paid on loan)
Fixed costs - example

- Payment = pmt(interest rate, term (months), “overnight cost”)
- Example:
  - Plant: 500 MW capacity
  - “Overnight” cost: $320,000,000
  - Term: 360 months
  - Rate: 7% (annual)
- Monthly payment: $2,129,000
  - Includes capital and interest payments
  - Over the term of the loan, 30 years
Fixed costs

• Ways of reporting capital costs
• Monthly payment for the capital (amortizing the loan) : $2,129,000

• This doesn’t change
  • No matter how much is produced
  • No matter what fraction of time the plant is run (capacity factor)
  • Whether or not the plant is open for business

• We will focus on *average fixed costs*:
  • Fixed cost per MWh generated
Fixed Costs [FC]

• AFC = monthly payment / monthly MWh generated
  • Where MWh per month = plant capacity (MW) * hours in month * capacity factor (cf)
• AFC falls as the capacity factor increases
  • Capital costs are spread over more MWh
Operation and maintenance costs [O&M]

• Costs of keeping the plant in operating condition
  • Average per month cost of staff, routine maintenance, security, etc.

• Must pay these costs each month unless you take plant out of service

• A plant may be taken out of service to reduce O&M
  • But, it takes time and money to bring back online
  • And you must still pay fixed costs

• Key point: some of these costs do not change as more electricity is produced
  • They are “fixed” in the short run: say a month at a time
  • Other O&M costs may rise as more electricity is produced
Operation and maintenance costs [O&M]

• For simplicity, we will divide up O&M costs into the fixed and variable components
  • The fixed part will go into fixed costs, and
  • The variable part will go into variable costs
• Keep in mind, if the plant is not used, we do not pay O&M costs
• Since we are thinking about plants that are in service, we just ignore O&M costs as a separate category and focus on fixed and variable costs
Variable costs [VC]

• How do production costs vary with the amount of electricity generated?

• Variable cost = monthly fuel bill
  • More fuel is required
    • Other things may change a little, but fuel is the lion’s share of variable cost
  • Monthly fuel cost = fuel price * heat rate * monthly output
    • The amount of fuel used per MWh (heat rate) varies with the type of plant
    • We make the simplifying assumption that heat rate is constant for a given plant

• The monthly fuel bill will depend on:
  • How much the plant is run, the capacity factor
  • How much fuel it takes to generate a MWh
  • And the price of fuel, of course.

• Capacity factor is percent of time used over a given time period
Variable Cost

![Graph showing the relationship between capacity factor and monthly variable cost. The graph has a linear trend with capacity factor on the x-axis and monthly variable cost (in millions) on the y-axis. The data points form a straight line indicating a direct proportionality.]
Marginal cost  [MC]

• What if I run the plant one additional hour?
  • Fixed cost and O&M do not change (the change in FC is zero)
  • Cost/hour ← incremental hourly cost
  • Basically, it’s the amount of additional fuel required per hour

• What if I generate one additional MWh of electricity?
  • Cost/MWh ← marginal cost (variable cost per unit of output)
  • The marginal cost may depend on how hard the plant is running
    • Heat rates of fossil plants may fall until the plant reaches minimum efficient output
    • As the plant approaches its design capacity, heat rates will rise again
  • For simplicity, we assume the heat rate does not change
    • So we take MC and average VC to be the same: the fuel cost to generate one more MWh
Marginal Cost

• Given a constant heat rate, MC is the same for each additional MWh generated
  • Think of it being constant over the reasonable operating range for a type of plant

• As we shall see, MC varies greatly for different kinds of plants
Average cost measures [AC]

• Average fixed cost: \( AFC = \frac{\text{fixed cost}}{\text{MWh}} \)

• Average variable cost: \( AVC = \frac{\text{variable costs}}{\text{MWh}} \)

• Average total cost: \( ATC = \frac{\text{(fixed cost + variable costs)}}{\text{MWh}} \)
  • So \( ATC = AFC + AVC \)
Average fixed costs: Example

• Back to our example 500 MW plant:
  • Fixed monthly finance payment: $2,129,000
  • Fuel price: $2.50/million Btu
  • Heat rate: 9 million Btu/MWh
  • Fuel cost per MWh: $2.50 * 9 = $22.5/MWh

• We will calculate monthly costs for a 720 hour month
  • Each 1% capacity factor is 7.2 hours of operation
  • And 5 MWh of output
Average fixed cost

![Graph showing average costs vs. capacity factor]

- **Average Costs**
- **Dollars per mWh**
- **Capacity factor**

Point labeled **AFC**
Average Variable Cost

![Graph showing Average Costs vs. Capacity factor]

- **AFC**
- **MC = AVC**
Average total cost

![Graph showing Average Costs with different cost curves labeled AFC, ATC, and MC = AVC against Capacity factor on the x-axis and Dollars per mWh on the y-axis. The graph illustrates the relationship between capacity factor and average costs, with different curves representing various cost components.]
More on ATC and AVC (MC)

- In our example, ATC is falling, while MC (AVC) is constant

- Also, note that AVC (MC) is everywhere below ATC
Opportunity cost: the good cost

• Anything you own (or have control over) might have value to someone else
  • They would be willing to pay you for it
  • If you use what you have, you give up the money from selling it
  • This is opportunity cost: what you can get for your asset if you don’t use it

• Suppose you win a car in a raffle
  • The raffle ticket cost $1.
  • Even if you already have a car, this second car is worth much more than $1 to you because you can sell it.
  • The possible sale price is the opportunity cost of keeping the car

• May you have high opportunity costs in life!
Levelized cost of energy [LCOE]

• Definition: The average cost per MWh (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle.
  • Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed capacity utilization rate for each plant type.

• LCOE = Levelized fixed costs + levelized variable costs

• Average (capital + O&M + variable) costs *at a given capacity factor*
  ❖ *Key point:* Since capital costs are fixed for the term of the loan, if O&M and fuel prices are likely to stay constant in inflation adjusted terms, then LCOE is equivalent to today’s ATC.
LCOE for a new plant

- We want to know average total cost for this plant over its lifetime
  - Assume factor prices are constant after adjusting for inflation
  - The cost of financing is fixed
  - The plant is expected to run at 80% capacity
  - LCOE is the ATC at the expected capacity factor
Levelized avoided cost of energy [LACE]

• What costs are avoided by building this plant?
• What it would cost to generate the electricity that is otherwise displaced by a new generation project.
  • What can you avoid doing if you build this new generation
  • If you are displacing an expensive alternative, the levelized avoided costs are higher and the project is relatively more attractive than if you were displacing an inexpensive alternative.
• LACE for an existing plant does not include (sunk) capital costs!
• If LACE > LCOE, then the project is relatively attractive from Society’s point of view.
Annual Revenue Requirement (another view)

- Annual Revenue Requirement (ARR) for a power plant shows the annual average cost of a unit of power generation capacity.
  - It represents the amount of revenue (per unit of capacity) that a power plant must earn to break even.
- ARR = Annual payment per MW capacity + variable costs
  - Remember, variable cost depends on the capacity factor
ARR calculation

• Fixed cost part:
  • $(\text{Monthly payment} \times 12) / \text{MW of capacity}$
  • $\frac{25,548,000}{500} = 51,096$

• Variable cost part:
  • Fuel cost per hour $\times (\text{hours per year} \times \text{capacity factor})$
  • $11,250 \times 8,760 \times \text{cf} = 98,550,000 \times \text{cf}$

• $\text{ARR(cf)} = 51,096 + (98,550,000 \times \text{cf})$
  • Ex: For cf = 10%, $\text{ARR(0.10)} = 51,096 + 9,855,000$
Annual Revenue Requirements compared

**Gas Turbine**
- OC = $350/kW
- MC = $35/MWh

**Coal Plant**
- OC = $1050/kW
- MC = $10/MWh

Assumptions: r = 0.1, T=40 years for coal, 20 years for gas
Costs of different plants

Applying cost analysis to different types of generators
Generators have different cost profiles

- Capital cost for an incremental plant
  - What is the efficient scale for a new plant?
- Heat rate, which determines variable costs
- O&M: fixed and variable
- Marginal cost
- Efficient duty cycle
  - What is an efficient average capacity factor?
  - Can the plant adjust output rapidly or should it run at a steady output?
  - What are the minimum and maximum efficient output rates?
Different kinds of plants

• Fossil fuel central station: baseload
• Hydro: run of river or dispatchable
• Renewable: run when available
• Peaker: run at high demand
• Backup generators (private, does not feed grid): high capital cost per KW of capacity, high variable costs [behind the meter generally]
• Coming up: distributed solar with battery backup
Fossil fuel baseload

• Coal, NGCC, Nuclear
• High initial capital costs:
  • The minimum efficient scale is quite large
• Low variable cost (low heat rate)
• High expected capacity factor
• Dispatchable: we can choose when to run them
• Some can adjust faster than others
  • Coal and nuclear are slow, NGCC pretty quick
Peaking units

- Combustion turbines, diesel generators
- Low initial capital cost
  - Efficient scale is small, essentially a packaged jet engine
- High variable cost
  - The heat rate is high, so variable costs are high
- Usually, low maximum capacity factor, say 30%
- Adjust very quickly to follow load
Hydro

• Very high initial capital cost
• Very low O&M costs
• Zero variable cost
• Capacity factor variable
  • Some can ramp up and down to follow load
  • Some are “run-of-river”
• A kind of energy storage
  • There is an opportunity cost of using water now
  • It may be more valuable later
Non-hydro renewables

- Initial capital cost varies according to scale
  - Minimum efficient scale can be quite low
- Very low O&M cost
- Zero variable cost
- Low and somewhat unpredictable capacity factor
- Use when available
  - Not dispatchable – can’t be called upon to follow load
  - You don’t choose when it is available
  - But may be able to match some loads, ex. irrigation
Backup generators

• High capital cost per kw of capacity
• Very high variable costs
• Very low capacity factor
• Behind the meter
  • Not part of grid capacity
Distributed renewables with battery backup

• Costs are falling very fast
• Can provide some grid services
  • May be used to lower costs of service
• But can result in mass defections from the grid
  • Puts a limit on what tariffs can be charged
  • Those who pay high tariffs are in a better position to self finance
Demand scheduling: a kind of capacity

• Some demand may be adjusted to available supply
  • Irrigation, EVs, storage, etc.
• Involuntary load shedding or
• Contracts with customers to reduce load
  • Voluntary load shedding at a price
• Low capital cost
• Marginal cost varies a lot, but there may be large reserves at relatively low cost
Storage: the next big thing

• Storage is a kind of supply
  • But may be in the form of short term demand reduction
  • Daily balancing
• Can be large scale or small
• Can follow load (up to a point)
• Costs are falling rapidly
• Can substitute for transmission infrastructure
Four examples

• A large, baseload fossil fuel power station
• A small peaker plant, say a combustion turbine or diesel generator
• A solar project
• Load reduction
  • Load shedding, demand reduction or private “behind-the-meter” generation
Common elements

• Market interest rate is 7% annually
• Term of loan is 30 years or 360 months
• A month is assumed to have 720 hours
• Fossil fuel cost is $2.50 per million Btu
• For combustion plants, the heat rate is assumed constant for any capacity factor
• Each type of plant has a preferred capacity factor
Plant 1: Big fossil

- We will use our earlier example:
  - Plant: 500 mW capacity
  - “Overnight” cost: $320,000,000
    - Fixed monthly payment: $2,129,000
  - Heat rate: 9 million Btu/MWh
  - Preferred capacity factor: 80%
  - Marginal cost is the fuel cost per MWh: $22.50
  - Each 1% of capacity generates 3,600 MWh of electricity
  - LCOE (long run average total cost): $29.90
Plant 1: Big fossil

Cost profile: Baseload

Dollars per mWh
Capacity factor

ATC
MC (AVC)
Plant 2: Fast peaker

- Plant: 15 MW capacity
- “Overnight” cost: $5,000,000
  - Fixed monthly payment: $33,265
- Heat rate: 15 million Btu/MWh
- Preferred capacity factor: 30%
- Marginal cost is the fuel cost per MWh: $37.50
- Each 1% of capacity generates 108 MWh of electricity
- LCOE (long run average total cost): $47.90
Plant 2: Fast peaker

Cost profile: Peaker

- ATC
- MC (AVC)
Plant 3: Standard solar

- Plant: 100 mW capacity
- “Overnight” cost: $100,000,000
  - Fixed monthly payment: $665,302
- Heat rate: 0 million Btu/MWh — no fuel required
- Preferred capacity factor: 25%
- Marginal cost is the fuel cost per MWh: $0
- Each 1% of capacity generates 720 MWh of electricity
- LCOE (long run average total cost): $37.0
Plant 3: Standard solar

Cost profile: Solar

- ATC
- MC (AVC)
Plant 4: Demand response

• Demand response is a special kind of plant
  • We will assume zero capital cost (for simplicity)
  • There is no fuel cost
  • There is just a flat fee per MWh reduced: $80/MWh
  • While load shedding does not have an explicit price, we assume that it is costly to discoms
    • Customer unhappiness
    • Political feedback
Marginal costs

Marginal cost of different options

Dollars per mWh

Type
- Baseload
- Peaker
- Solar

Capacity factor
Three plants compared

Average total costs and LCOE

- Baseload
- Peaker
- Solar
Three plants compared

**Average total cost and marginal cost**

<table>
<thead>
<tr>
<th></th>
<th>Baseload</th>
<th>Peaker</th>
<th>Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capacity factor</strong></td>
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<td>50</td>
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<tr>
<td><strong>Dollars per mWh</strong></td>
<td>0</td>
<td>25</td>
<td>50</td>
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</table>

The graph compares the average total cost and marginal cost for Baseload, Peaker, and Solar plants across different capacity factors. The x-axis represents the capacity factor, while the y-axis shows the dollars per mWh.
Putting it all together

• Now, we have the marginal and long-run average costs for four different ways of addressing electricity demand

• The next picture shows the cost of 100 MWh increments from each of our plant types (including demand reduction)
Another view of all four options

Marginal cost and LCOE of capacity

Marginal cost vs MegaWatts

- Solar
- Baseload
- Peaker
- Demand reduction
Different types of plants, different services

The importance of flexibility and other characteristics of generation
Objectives

• Consider the different ‘services’ created by a plant
• What characteristics of a plant have value?
  • Flexibility and ancillary services
• How is that value compensated?
New plants have different flexibility

- **Ramp rate**: How quickly the plant can increase or decrease power output
- **Ramp time**: The amount of time it takes from the moment a generator is turned on to the moment it can start providing energy to the grid at its lower operating limit
- **Capacity**: The maximum output of a plant
- **Lower Operating Limit**: The minimum amount of power a plant can generate once it is turned on
- **Minimum Run Time**: The shortest amount of time a plant can operate once it is turned on
- **No-Load Cost**: The cost of turning the plant on, but keeping it "spinning," ready to increase power output
- **Start-up and Shut-down Costs**: the costs of turning the plant on and off
Why is generator flexibility important

- Uncertainty in supply and demand
- Proper compensation to encourage investment
- Increased availability of wind and solar
- Immediate response and incremental supply adjustment
- Unresponsive demand in the short run
  - Can demand response act as flexible supply?
Ancillary Services

• Voltage/frequency regulation
• Spinning and non-spinning reserves
  • Quick response supply
• Reactive power
• Black start capability

• Which plants provide these?
• How will batteries, wind and solar fit in?
Things that are valuable need compensation

• In thinking about your capital investments, think about whether these generation attributes have value

• And whether you have incentive to provide them
When to run existing plants

What our cost analysis tells us about choosing which plants to run
Objective

• With cost curves in hand, we explore
  • When it is advantageous to run an existing plant
  • How plants make a profit
  • When would you offer to sell additional power?
  • What does this tell us about the order in which we should choose to use existing plants?
When to run an existing plant

• Suppose you own a plant like Plant 1 in our earlier example

• Key facts:
  • Fixed monthly payment: $2,128,968
  • Marginal cost is the fuel cost per MWh: $22.5
  • LCOE (long run average total cost): $29.9
  • LCOE based on an average capacity factor of 80%
  • Plant is not under a long-term contract to a discom - merchant

• Question: What do you make each month if you do not run the plant?
An offer

• You get an offer from a discom to buy 50% of the capacity of your plant

• At 50% capacity (250 mW),
  • Your average total cost per MWh is $34.3
  • Average fixed cost is $11.8
  • Marginal cost is $22.5

• What is the minimum price you would take?
Cost profile: Baseload

- ATC
- MC (AVC)
The bottom line

<table>
<thead>
<tr>
<th>Price</th>
<th>Net position</th>
<th>Relative to not running the plant</th>
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</thead>
<tbody>
<tr>
<td>(Don't run plant)</td>
<td>($2,128,968)</td>
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<tr>
<td>$20.00</td>
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</tr>
<tr>
<td>$35.00</td>
<td>$121,032</td>
<td>$2,250,000</td>
</tr>
</tbody>
</table>
Conclusion

• Earnings are greatest from running the plant whenever the price is greater than variable cost.
  • At any price above average variable cost (here, $22.50), running the plant increases earnings
  • Even if you can’t make a profit, you are losing less money.
  • At less than $22.50, you should not run the plant.
  • Note: in this example AVC = MC.
Cost profile: Baseload

Dollars per mWh vs. Capacity factor

ATC
MC (AVC)
How do plants make a profit?

• For an existing plant, the plant makes a profit when price is at or above ATC for a given capacity factor.
  • A price equal to ATC implies that investors are earning a normal rate of return on their investment.
  • A price above ATC implies that the plant is earning “scarcity rents” or “extra-normal profits”
    • This is the extra profit from running a low cost plant at time when prices are high.
Cost profile: Baseload

Dollars per mWh versus Capacity factor

MC (AVC)
Conclusion

• A plant makes a normal rate of return (economists call this zero “economic” profit) when price = ATC
  • Price > ATC implies economic profit (scarcity rents)
  • Price < AVC implies increasing losses (so shut down)
  • Price in between AVC and ATC implies running the plant to decrease losses due to fixed costs
• Running when price > AVC recovers as much of fixed costs as possible
Changing prices

• As prices change during a day, a month or a year, then a plant will have periods with extra profits and periods with losses.
  • As long as this averages out to at least average variable costs, the plant should be made available to run.
  • Since you are covering your variable costs, there are net earnings that can be applied to paying some fixed costs.
  • If price stays below AVC, the plant should be taken out of service, to minimize losses.
Cost profile: Baseload
When to offer to sell additional power

• Up to now, we have discussed when to operate a plant and how much money it will bring in.

• Another (and related) question: when should I choose to sell an additional MWh from my plant?

• Easy answer: whenever it makes me more money than it costs me
Marginal cost review

• Marginal cost is defined as the cost to you of producing an additional unit of output, here, a MWh.
  • This includes fuel, staff, wear and tear, etc.; any consequences of generating one additional MWh
  • In my examples so far, I have assumed (for simplicity) that MC is constant, but for most plants, MC probably falls at first, is flat for a range, and then rises at very high capacity factors.
  • Either way, the definition is the same.
Does additional output make money?

- If price > MC, then selling one additional unit makes me more money than it costs me.
  - So, whenever price > MC, I should expand production
  - When price < MC, production should be reduced
  - Note: for my simple example where MC is constant, production should expand to the lowest point on the ATC curve.
    - If MC starts to rise at high capacity factors, then the lowest ATC will be at less than 100% capacity.
Which plants should be run?

• Let’s suppose that we need to bring some additional capacity online for the next hour.
• For this example, each of our three plants, baseload, peaker and solar have 100 MW available.
  • And demand reduction is available as well.
• Which plant(s) should we use?
• First, what would be the long-run contract price for each source? (Hint: LCOE)
Levelized cost of energy

Levelized cost of energy (long-term contract price)
Which plant should we run?

• Suppose you owned these three plants.
• You need an additional 100 MWh.
• Which plant should you run in order to make the most money?

• To answer this, let’s look at the “supply stack”.
The supply stack

Marginal cost and LCOE of capacity

MegaWatt hours

Solar Baseload Peaker Demand reduction

Dollars

0 100 200 300 400 500

0 25 50 75 100
Cost of incremental supply

• What does it cost you to produce the extra 100 MWh?
  • Solar: $?
  • Baseload:
  • Peaker:
  • DR:
Cost of incremental supply

• What does it cost you to produce the extra 100 MWh?
  • Solar: $0
  • Baseload: $?
  • Peaker:
  • DR:
Cost of incremental supply

• What does it cost you to produce the extra 100 MWh?
  • Solar: $0
  • Baseload: $22.50 * 100 = $2,250
  • Peaker: $?
  • DR:
Cost of incremental supply

• What does it cost you to produce the extra 100 MWh?
  • Solar: $0
  • Baseload: $22.50 * 100 = $2,250
  • Peaker: $37.50 * 100 = $3,750
  • DR: $80.00 * 100 = $8,000

• What if you had used LCOE as your guide?
  • Baseload, then Solar, then Peaker, then DR
  • You would have spent $2,250 instead of $0
Let’s talk price

• Now suppose that you are offered $20 per MWh for additional power.
  • What should you do?
• Consider different levels of demand that might occur over the year.
  • Responding to demand in marginal cost order is the most profitable and cost-effective.
The supply stack

Marginal cost and LCOE of capacity

- Solar
- Baseload
- Peaker
- Demand reduction

MegaWatt hours

Dollars
Conclusion

• If they were your plants, you would make more money by operating them in order of increasing MC (aka: merit order)

• If you used LCOE, you would make much less money.

• For a given price, you maximize profit if you run any plant for which price > MC.
  • This makes more money than if you use LCOE (or long-term contract price).
Conclusion

• A plant may often operate even when it is losing money.
  • As long as it is covering variable costs

• Key Point:
  • Even if a plant operates at a loss at times, it may be profitable on average so long as there are periods when it can earn scarcity rents.
Investment in New Plants

The basic economics of decisions to build new capacity
Objectives

• When does it pay to build a new plant?
• Profiting from day-ahead sales only
• Long-term contracts for new capacity (PPAs)
• Capacity payments plus day-ahead sales
  • Why capacity payments?
• Mixing PPAs and day-ahead procurement
Building a new plant

• Earlier, we discussed how the levelized cost of energy is calculated
  • The average total cost at an expected capacity factor
  • The capacity factor used will have low ATC
• Since the LCOE includes a normal market return to capital investors, then LCOE should be the price of a contract for power from a new facility
  • A higher price means positive economic profits
  • A lower price means a loss to investors
Recall: Levelized cost of energy

- Definition: The average cost per mWh (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle.
- Average (capital + O&M + variable) costs at a given capacity factor
Variable prices for electricity

• If electricity value were constant, this would be easy
  • Long-term contracts would be for a fixed price: LCOE
• But, the value of a mWh generated is not constant
  • Both demand and available supply vary during the day and across regions and seasons
  • In the longer run, growth in the economy implies some future, but uncertain, growth in demand
  • In the longer run, technologies of generation will change in unpredictable ways, so the cost of supply will change
A revised supply example

• Suppose we have our three generation technologies as before except with a new lower LCOE for solar
  • It is now the lowest LCOE
  • But it can’t be stored and does not follow load, so we will still need baseload power and peakers and DR
  • Since solar has a zero MC, it is always run when available
• The long-run expected price of electricity can’t be below the LCOE for baseload
  • Or the plant would not receive financing
Levelized costs of energy – revised example

![Graph showing levels of energy cost and demand reduction](image)
Why ever build a peaker?

• To understand about contracting for new capacity, it is well to start with peaking plants
  • Most of the time, price will be below peaker MC
  • For a peaker to be built, price must spend enough time above peaker LCOE so that the plant earns enough to be profitable
  • If an investor were sure that this would occur, then the plant would be built with or without a power purchase agreement (PPA)
New supply stack

Supply stack

Dollars

MegaWatt hours

Solar  Baseload  Peaker  Demand reduction
Long-run profits from short-run trading

• How could an investor make this work?
  • Watch the price on the electricity exchanges and sell into the day-ahead market whenever the price is above MC
    • There must be sufficient day-ahead buyers for this to work
  • Or in countries with day-ahead procurement auctions, bid into the auction
  • If you can average a 30% capacity factor at a price of LCOE or better, then you make a profit
  • If you know the price will spend plenty of time above LCOE, you will be able to run the plant at a profit.
• Since the investment is risky, it requires a higher return to be profitable (taking risk must be compensated)
The “scarcity” pricing story

• Let the market price for electricity vary according to scarcity
• Have generators announce prices for their product day-ahead
• Accept bids in merit order

• Since plants will earn scarcity rents during high price times, they will be profitable even if P < ATC at times
• Firms will build capacity until “economic profits” are zero
Marginal Cost Curve for Electricity

Figure 2. Competitive supply and demand in Pennsylvania-New Jersey-Maryland (PJM)
A newer version of the PJM supply stack
Local peaks can be much higher

• Because of transmission congestion, some localities may experience high prices
• Even when adequate system-wide capacity is plentiful
  • This provides incentive to provide additional capacity where it is most needed
Peaker versus baseload

• Demand varies over the course of the day

• You wouldn’t want to build a baseload plant to meet demand that only lasts for a few hours a day
  • Building and running a peaker is more cost-effective
  • Peaker runs at 100% for just a few hours on most days

• A baseload plant would not be profitable, but would keep MC too low, so peaker would not be built
Conclusions

• A plant is worth building if price will spend enough time above LCOE (and MC, of course) to pay back the investment and make a normal return.
• This does not require a long-term contract
  • Especially for smaller types of generators
• Profits can be made selling in the day-ahead market
• But it can be a risky activity
Limits on price

• Key point: if prices cannot go high enough so that peaker can earn enough scarcity rents to be profitable, then the peaker will not be built.

• If the peaker is not built, then supply will jump from baseload directly to demand reduction
  • Either baseload is overbuilt
  • Or DR is used too often
New supply stack

Supply stack

MegaWatt hours

Dollars

Solar Baseload Peaker Demand reduction
Risk and long-term contracts

• Investing in power plants is risky, so investors, gencos and discoms may shift risk through a long-term supply contract, a power purchase agreement (PPA).

• PPA terms:
  • Capacity payment: guaranteed payment to cover the capital cost in return for making the plant available
  • Energy charge: covers variable costs of day-ahead scheduled generation
  • Deviation payment: for non-provision of scheduled generation
  • The price of the contract will include a risk premium based on the perceived risks about future costs and prices
More on risk

• PPAs do not eliminate the risk. They shift it.
  • The discom takes on the risk in return for not paying a risk premium to the investor

• One way of limiting discom risk is to limit the quantity of power purchased through PPAs to a likely baseload

• Other generation can be purchased either by shorter-term contracts or by participating in exchange sales

• Later, we will discuss other contractual tools for limiting or sharing risk.
Capacity payments

• Even in countries with very active day-ahead exchanges, there may be limits on prices that may be charged
  • The reason for this is that it may be hard to tell the difference between a high, but competitive, price and a high price due to market power.
  • A ceiling on prices will lower scarcity rents to generators and will prevent some generation from being built
  • This leads to the “missing money” problem
    • Not enough scarcity rents to cover average costs
New supply stack
More on capacity payments

• Payments may be part of a PPA, as we have already seen, or other procurement mechanisms (say auctions)
  • Such capacity payments will not be equal to capital cost
  • It is the payment needed to draw capacity into the market, given that expected scarcity rents are lower due to limits on prices
  • Any expected rents will reduce the needed capacity payment
  • Capacity payments are just one way to solve the missing money problem
Conclusions

• A plant is worth building if it can cover its average total cost for the capacity factor at which it operates
  • Since prices vary, this will be achieved on average, with price being higher and lower than LCOE at various times

• Payment for a plant can be variable or set by contract
  • Selling in day-ahead auctions or exchanges
  • Power purchase agreements (sharing risks)

• If prices are capped, capacity payments may be needed even in markets with active day-ahead markets
Contracts, Auctions and Exchanges

The mechanics of energy exchange
Objectives

• Explore different ways electricity can be traded
  • Long-term contracts, PPAs
    • Payments for capacity, energy and deviation
  • Banking
    • Informal bilateral barter
• Auctions for power (and for capacity)
  • Uniform-price, procurement auctions
• Exchanges
The supply stack

Marginal cost and LCOE of capacity

MegaWatt hours

Solar  Baseload  Peaker  Demand reduction

Dollars

0  100  200  300  400  500

0  25  50  75  100

MegaWatt hours
Long-term contracts

• Any large, long-lived capital investment involves a long-term financing contract
• Our focus is on contracts between the generator and the potential buyer of the generator’s output, usually a discom
• These contracts are a feature of electricity markets everywhere
Important general characteristics

• Power contracts are large, relatively infrequent transactions between generators and buyers
  • Large sums, long commitments and so, considerable risk
  • There is risk over the prices of both inputs and output
  • With a limited number of potential traders and low liquidity, the market may not be competitive
  • PPAs are not suited to rapidly responding to new information about costs, demand and prices
  • But they provide some certainty to investors
Value of PPAs

• In spite of being cumbersome, PPAs are widely used
• They are an important adjunct to generator financing
  • It may be very costly for an entrepreneur to get financing without a PPA in place
• They reallocate risk between generator and buyer
• They facilitate long-range capacity planning
• Having a significant share of power under PPAs may reduce incentives for market manipulation
A fixed instrument for the predictable

• Long-term fixed-price PPAs are best applied to the most predictable portion of the electricity market
  • Current baseload demand is an almost sure bet
  • Incremental demand 20 years hence is highly speculative
  • Solar PV, with its zero fuel cost and run-when-available character is at low risk of not running
  • Peaking gas turbines are less well-suited to long-term PPAs
  • What about batteries?
Price formation: the scarcity signal

• The RFP – contracting process does not provide clear price signals
  • Non-uniform: contracts are bundles of different attributes
  • The scope of RFPs may be limited
  • The transaction may not be arms-length
  • The terms reflect party assessments of long-term risks
  • Existing tariffs determine the terms of the contract
• In some cases, discoms are the only buyers
• Contract terms do not give reliable information about the costs of generation
PPA terms

• Capacity payment – a payment sufficient to ensure that the capacity is made available
  • This may be less than actual financing cost
  • Can the generator earn scarcity rents?

• Energy payment – a payment for energy delivered
  • Price may be fixed or may change in specified ways
  • Contingent pricing makes the contracts more complicated

• Deviation terms – what happens if the energy provided deviates from the agreed amount?
Conclusions

• PPAs are best for the most predictable part of demand
  • Less predictable demand may best stay outside of PPAs
  • PPAs may include capacity and energy payments
  • PPAs shift risk but do not eliminate it
• They help generators arrange financing
• Some fixed price contracts can reduce manipulation
• Contracting for PPAs is time-consuming and does not provide good information about market prices
Banking: An informal market for power

• “Banking” is a form of seasonal bartering for power
  • Discoms with an excess of power in one season will offer it to discoms with excess demand
  • In return for a return flow of power in another season when the pattern of excess supply and demand is reversed.
  • Discounting for time is in terms of power flows
  • No cash changes hands
  • Not a large factor in Indian electricity markets
Auctions

- An auction is an organized market
- An electricity auction is for procurement
  - Sellers are gencos
  - Buyers are discoms (or other direct buyers)
  - The auctioneer may be an exchange or a system operator
- Buyer announces the quantity needed
- Seller posts quantity-price bids
- Auctioneer matches buyers and sellers according to the auction rules
Why auction?

• Auctions are an extremely inexpensive way of bringing many buyers and sellers together to trade a commodity
  • High liquidity means competitive markets
  • Very low cost exchange
  • Highly transparent, rule-based exchange
  • All traders treated equally
  • Anonymous trading
  • Easily monitored by the auctioneer
Types of auctions

• “Auction” is a mechanism for facilitating exchange
  • A discrete event or a continuous market where the trading occurs as bids and asks arrive

• Discrete auctions may be:
  • Sealed-bid versus sequential
  • Pay-as-bid versus uniform price

• Electricity procurement auctions are usually:
  • Sealed-bid, uniform-price
How day-ahead auctions work

• Buyer sets quantity needed for the next day
  • 5-minute intervals
  • By region (to account for transmission constraints)
• Sellers bid a quantity and a price for each period
• Auctioneer sorts the bids in increasing order and accepts bids up to the quantity required
• **All sellers receive the same price, $p^*$**
  • The value of the first rejected bid
Sealed-bid, uniform-price auction

All winning bids are paid $8.5
Why uniform price auctions?

• Equivalent to pay-as-bid in theory
  • Seller revenues expected to be the same
• But, in practice, uniform price auctions are thought to work better for electricity markets
  • They provide effective price discovery
  • Sellers have incentive to bid their actual values
  • Honest bidding leads to prices matching scarcity
  • So, intermittent sellers make needed scarcity rents
What will sellers bid?

• We discussed earlier that generators have incentive to operate their plants whenever price is greater than MC
  • So what would a genco bid in a uniform-price auction?
• It turns out that, **in a competitive auction**, bidders will want to bid their actual MC
  • Bids above $p^*$ will not change the closing auction price
  • But will result in losing some valuable sales at $> MC$
  • Bids below $p^*$ won’t change the closing price
  • But will result in some production with price $< MC$
A day-ahead auction

Supply stack

- Solar
- Baseload
- Peaker
- Demand reduction

MegaWatt hours

Dollars
Double-sided auction: OTC trading

• Suppose you just allow buyers and sellers to continuously post bids (to buy) and offers (to sell)
  • One reason you might do this is to allow very short-run matching of supply and demand during the day
• Genco has unused capacity
• Buyer needs additional power
• Bids and offers are posted, if bid >= offer, it’s a deal
  • Otherwise revise bid/offer or wait for more bids/offers
Double auction trading
Conclusions

• Auctions match buyers and sellers at low cost
  • Result in effective price discovery
  • Limit market manipulation
  • Maximize the value from exchange
  • Widely used in electricity markets
  • Provide liquidity and transparency

• Double-sided auctions can operate continuously
Exchanges

• An exchange is just a place to go to trade something.
• Electricity exchanges provide opportunities to trade electricity that is not under long-term contract
  • There are considerable advantages to having some of the electricity demand and supply arranged through an exchange.
• Exchanges may hold both discrete, day-ahead auctions and continuous, double-sided markets (OTC)
Key functions of exchanges

• The primary role of an exchange is to match willing buyers to willing sellers
  • Low cost trading
  • Uniform commodity contract
  • Ease of identifying trading partners
  • Anonymity
  • Reduced credit and delivery risk
  • Competitive pricing

• Exchanges actually reduce risk by allowing ex post adjustment of positions
Conclusions

• Exchanges facilitate electricity trading through both sealed-bid and continuous auctions
• Exchanges increase flexibility and value by facilitating trading
• They are widely used in many countries for managing electricity delivery
An auction exercise

• We will try a continuous double auction:
  • Buyers and sellers will post bids and offers online
  • Everyone has three possible trades
  • Sellers know the cost of their goods
  • Buyers know the value they earn if they obtain the goods
  • You can change your bids/offers until the time is up
  • All bid > offer pairs result in a trade
Log in

• Go to: http://veconlab.econ.virginia.edu
• Click: “Log in as Participant” then “Login”
• Session name: emkt8
• Type in your name, don’t bother about the password
• Write down your ID (just in case)
• “Continue with instructions”
• “Finished with instructions”
Bids and Offers

• It’s very simple:
  • Buyers offer less than their value (so to make some profit)
  • Sellers offer (ask) more than their cost (ditto)
• The Bid/Ask Book records current bids and asks
  • Green for pending trades
  • Red for no deal (yet)
• Change your bids until you make the most money
<table>
<thead>
<tr>
<th>Unit</th>
<th>Your Cost</th>
<th>Your Ask</th>
<th>Provisional Price</th>
<th>Provisional Earnings</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
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<td>**</td>
<td>*</td>
<td>$0.00</td>
</tr>
<tr>
<td>2</td>
<td>$3.50</td>
<td>**</td>
<td>*</td>
<td>$0.00</td>
</tr>
<tr>
<td>3</td>
<td>$4.50</td>
<td>**</td>
<td>*</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

**Total Provisional Earnings:** $0.00
Round 1, Buyer 3

Round 1 Will Be Stopped Shortly, Press Update.

Enter/Alter Bid Prices and Submit:

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<thead>
<tr>
<th>ID</th>
<th>Bid</th>
<th>ASK</th>
<th>Unit</th>
<th>Your Value</th>
<th>Your Bid</th>
<th>Provisional Price</th>
<th>Provisional Earnings</th>
</tr>
</thead>
<tbody>
<tr>
<td>3(you)</td>
<td>$4.00</td>
<td>$4.00</td>
<td>1</td>
<td>$6.50</td>
<td>4</td>
<td>$4.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>3(you)</td>
<td>$3.50</td>
<td>$5.00</td>
<td>2</td>
<td>$5.50</td>
<td>3.5</td>
<td>$4.00</td>
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<td>$6.00</td>
<td>3</td>
<td>$2.50</td>
<td>2</td>
<td>$4.00</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

Total Provisional Earnings: $0.00

Submit/Update/Continue
Market closing

• Make your bids/asks before the market closes
• All pairs that are in the money will go through
  • Bids > Asks
• Your earnings will add up across markets
• We’ll try a few things:
  1. Trade for a session
  2. Change demand and see how things change
  3. Impose a price ceiling
Managing Risk

Uncertainty affects outcomes for distribution and generation companies
Topics

• Sources of risk
• How might the system (distribution company) respond?
• Operating existing assets with contracts for differences
• Option theory and long term investments
Sources of risk and uncertainty

• Fuel price
• Growth and demand
• New regulations
• New investment and competition
• Technology costs
• Other...
Consider fuel price risk in contracting

Contract terms, a standard two part contract:

Fixed (take or pay) + Variable Costs

Coal and natural gas prices are not stable.

What kind of cost does this risk impose on the generator or the distribution company? Who has to carry the costs of the uncertain fuel price?
Tariffs and expected costs

Imagine the tariff (electricity price or average revenue) is set to allow the distribution utility to recover expected costs (average total costs).

Expected fuel prices ($/Btu) * heat rate (Btu/MWh) + fixed cost ($/MWh) => electricity costs ($/MWh)

Tariffs vary by customer class, but the intent is to minimize the gap between ACS and average realized revenues. To what extent is this accomplished?
Actual cost of service is likely to differ from the expected average.
When should a generator not run?

Revenue is less than average costs but may be greater than variable cost.
A thought experiment:

Imagine fuel price outcomes are uniformly distributed with equal likelihood: low, medium, high. Then the expected cost is:

\[
\text{Expected Cost} = F + \frac{V_L}{3} + \frac{V_M}{3} + \frac{V_H}{3}
\]
Perhaps the electricity tariffs are set equal to expected costs.

\[
\text{Price} = \text{Expected Costs} = F + \frac{V_L}{3} + \frac{V_M}{3} + \frac{V_H}{3}
\]
What happens if fuel prices are high and the distribution company curtails a generator?

Revenue = 0
Pay fixed costs = F
Maybe an additional “social cost” of curtailment = Z
Possible outcomes and decisions:

Low fuel price, the net revenue is:
\[ R_L = P - F - V_L > 0 \]

Middle fuel price:
\[ R_M = P - F - V_M = 0 \]

High fuel price:
Serve customers? Net revenue: \( R_H = P - F - V_H < 0 \)

or

Curtail? Net revenue: \( R_C = -F - Z < 0 \)

\[ \Rightarrow \text{Curtail if: } P - V_H < -Z \]

that is, if short term loss is less (worse) than the cost of curtailment
What happens for the distribution company?

**Low fuel price**: Positive net revenue. Are there rewards? Where does money go? Is there criticism that electricity price is too high?

**Middle fuel price**: Revenues equal costs.

**High fuel price**: If there are negative net revenues, does the government subsidize electricity? When is curtailment likely? Will the fixed cost part of contracts always be paid?
Insuring (hedging) against fuel price risk with a *contract for differences*:

How much would you pay to avoid uncertainty? How much would you pay for a “certain” fuel price? Label this H.

\[ W[\tilde{V}] = W[\bar{V}] - H \]

that is,

\[ W \left[ \frac{V_L}{3} + \frac{V_M}{3} + \frac{V_H}{3} \right] = W[V_M] - H \]
Hedging cost

The hedging cost offers insurance for fuel price outcomes.

(Maybe the hedging cost should be part of the ARR.)
Contract for differences: Offers electricity supply at a guaranteed price. The contract pays the difference between total cost and the strike price.
A contract for differences has continuous payments

Source: New Zealand Electric Authority (Te Mana Hiko)
The CFD is widely applied for operating and pricing existing assets, and sometimes for new assets (for example to hedge a power purchase agreement).

When fuel price risk is a concern, a contract for differences is likely to shift risk from distribution utility to the counter-party of the contract.

But if demand risk is a concern, a power purchase agreement contract is likely to benefit the generator, and shift risk from the generator to the counter-party of the contract (which could be the distribution utility).
Notes:
1) The CFD is usually for a fixed quantity of supply.
2) Also, the counter-party could be the generator, a fuel company, or an independent financial firm.
3) The CFD is a tradable futures contract. It has an fixed initial price (strike price). The value of the contract changes with new information, say, about fuel costs for example.

- Uncertainty raises the “hurdle rate” for investments, and does so more so for large and/or long-lived investments (baseload). Hence, uncertainty favors smaller, modular investments (renewables?).
Summary

• Risk and uncertainty is common and seems to be a growing characteristic of the energy sector.

• Contracts for differences do not eliminate risk but allow it to be shared efficiently.

• CFDs enable a more efficient utilization of assets and sometimes apply to new investments.

• Option theory suggests modular investments have an advantage in uncertain times.
System Management

Managing grid resources for reliability and affordability
Dispatch: Which plants will run?

- Earlier, we showed that **system costs are lowest** if plants are run in order of increasing marginal cost (merit order).
- The level of demand will determine how far we go up the merit order stack:
  - Price is determined by the MC of the most costly unit run.
  - During low demand periods, low-cost, baseload generators will set the price.
  - In high demand periods, higher cost generators set the price, while lower cost facilities earn scarcity rents.
The supply stack again

Marginal cost and LCOE of capacity

<table>
<thead>
<tr>
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<th>Peaker</th>
<th>Demand reduction</th>
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MegaWatt hours

Dollars
Who decides on dispatch?

- Discoms with plants under contract
  - Limited set of available gencos
  - Dispatch by contract or by merit order
- System operator
  - All gencos sell through one dispatcher
Merit order dispatch

• With merit order dispatch, the marginal costs are determined in the day-ahead market
  • A procurement auction can be held for the forecast need
  • On the day of generation, true-up to actual realized demand can be met with fast response resources at their marginal cost
  • Generators not meeting their obligation are charged for replacing that power at the market price
• On the day of service, true up to actual demand is done via a “real-time” market and market for ancillary services
The supply stack again

Marginal cost and LCOE of capacity

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MegaWatt hours

Dollars
Merit order incentives

• Under dispatch by merit order periods of high prices compensate high fixed-cost generators through scarcity rents
  • Limits on prices may result in the need for separate payments to capacity
Too many long-term contracts

• If all power is under long-term, take-or-pay contracts for a fixed price, then dispatch would be by LCOE
  • Costs of generation are higher or curtailment is more likely
  • There is incentive to build too much baseload and too little peaker
• Solar is more complicated. Even with low LCOE, high solar penetration may lower prices to solar when it is available
  • Resulting in too little scarcity rents
  • What if solar were the marginal (price-setting) generator?
  • Incentives to shift demand to times when solar is available
The supply stack again

Marginal cost and LCOE of capacity

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</table>

Marginal cost and LCOE of capacity:

- Solar
- Baseload
- Peaker
- Demand reduction

MegaWatt hours:

- 0
- 100
- 200
- 300
- 400
- 500

Dollars:

- 0
- 25
- 50
- 75
- 100

Dollars per mWh:

- 0
- 25
- 50
- 75
- 100

Type:

- Baseload
- Peaker
- Solar

Marginal cost and LCOE of capacity.
Conclusions

• Dispatch by merit order results in the lowest cost of power generated
  • And provides incentives for a mix of generators

• Using long-term, fixed-price contracts for most dispatch can raise costs
  • May over-emphasize big baseload plants
Dispatch by locality

• Dispatch across more than one locality will generally lower costs
  • Suppose State B has 100 mWh of baseload
  • And State S has 100 mWh each of solar and peaker
  • State S and State B both need 75 mWh today
  • Without trade between the states, 25 mWh of zero cost solar will go to waste and 25 mWh of baseload will run instead, with variable costs of $22.5*25 = $562.5
    • The least-cost dispatch would be 100 mWh of solar and 50 mWh of baseload
Multi-state dispatch

• Taking advantage of cost savings from multi-state, merit order dispatch needs:
  • Bidding mechanism to build the supply stack
  • Transmission capacity (and pricing congestion)
  • Dispatch coordination

• Each one of these has benefits, but together, the benefits are even greater
Transmission

• Grid segments have limited capacity
• When a segment is congested, one plant’s production can interfere with another’s, if they are on the same side of a congested segment
• Prices will need to vary by location if there is congestion
• A “load pocket” is an area where local demand must be met by local generation due to congestion
  • Even if it would otherwise be cheaper to buy from another location
  • In a load pocket, local plants can have significant market power
  • High prices will reflect market power rather than generation costs
Grid investment

- Transmission planning needs to respond to present and future congestion
- It also needs to be at the appropriate scale
  - Planning transmission investments needs to be multi-regional
  - Local incentives are diffuse, grid adequacy is a public good
  - Generators in load pockets can profit from congestion
- The relationship between renewables and transmission investment is complicated
  - Distributed power can increase or decrease need for grid enhancement
Who dispatches?

- Dispatch could be handled by a state discom or by an ISO (independent system operator)
  - An ISO can combine multiple discoms for cost advantage
- Either arrangement *could* use merit order dispatch
- What is the basis for local discom dispatch choices?
- How does this affect choices for multi-regional cost savings?
What is dispatched?

• Day-ahead: forward decision about load and reserves
• Real-time: spot decision about load and reserves
• Other ancillary services:
  • voltage regulation, black start, etc.
• Transmission services
  • Financial transmission “rights” may be traded
  • But actual use is determined by generation dispatch
Voltage/frequency regulation

• Mismatch between demand and supply results in frequency deviations
  • Can be managed by changing generation or by demand reduction
  • Frequency regulation can be handled with dispatchable regulation reserves
  • The deviation settlement mechanism is designed to give generators incentive to adjust generation to adjust the frequency
Deviation settlement mechanism

• Frequency falls outside of acceptable range
• Initial price signal is sent out to gencos
• Gencos independently decide how to respond to the announced deviation price
• Depending on how all gencos respond, the price will adjust
• Generators receive a price that is a mix of the announced and final deviation price
  • Based on the deviation from their contracted generation amount
Dispatch-based frequency regulation

• Various levels of reserves are bid in the day-ahead market
  • Price depends on the level of commitment of the reserves
  • Cost or opportunity cost

• Reserves and regulation services are offered in the real-time market

• Reserves are dispatched in merit order (at marginal cost) as needed
Distributed energy services

• Definition: energy (and ancillary) services that are attached to the grid at the distribution level rather than the transmission level
  • Lower voltage connection to the distribution system
  • Two way flow
  • Aggregated small sources
  • Possibly intermittent (as with renewables or demand management)
  • Geographically diverse
  • Batteries, renewables, demand reduction, others...

• Key new challenge to grid management
Conclusion

• Price-based dispatch can work for ancillary grid management services as well as for energy