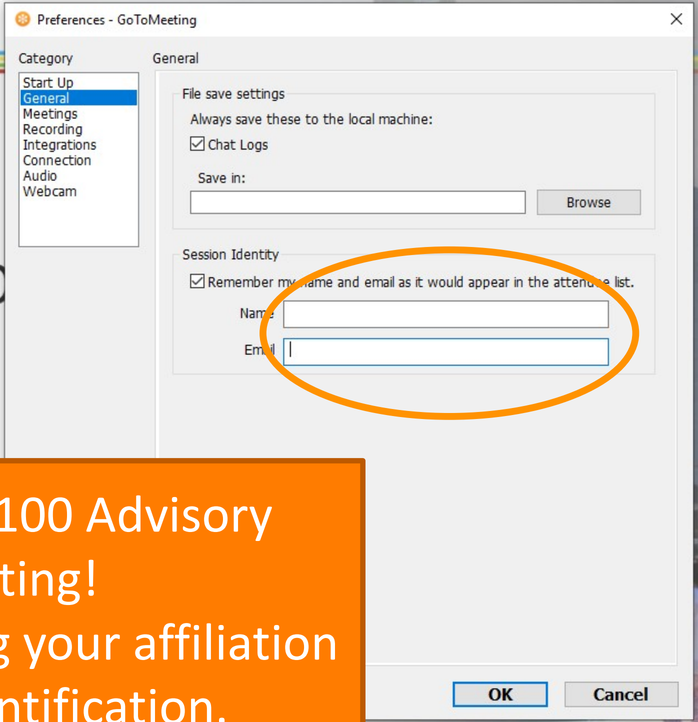
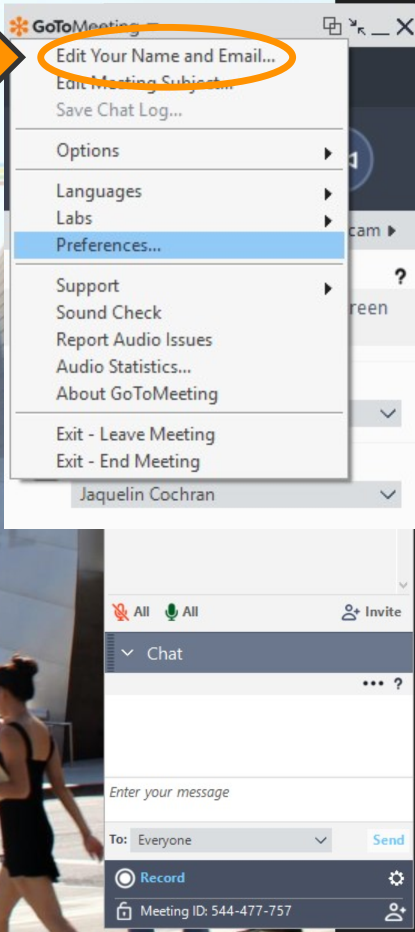
LA100

The Los Angeles 100% Renewable Energy Study

Advisory Group Meeting #11





Welcome to the LA100 Advisory Group meeting!
Please consider adding your affiliation to your name identification.

Los Angeles Department of Water & Power

NREL Transforming ENERGY

LA100

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Advisory Group Meeting #11

Virtual Meeting #2

Los Angeles Department of Water & Power

NREL Transforming ENERGY

Agenda

May 14

- Welcome
- Electricity Demand Projections and Demand Response
- Discussion/Q&A

Today (May 21)

- Welcome
- Renewable Options and Trade-offs to Go from 90% to 100% RE
- Discussion/Q&A

May 28

- Welcome
- Local Solar and Storage
- Discussion/Q&A

June 4

- Follow-up Q&A

Tips for Productive Discussions

Let one person speak at a time

Keep phone/computer on mute until ready to speak

Help ensure everyone gets equal time to give input

Type "Hand" in Chat Function to raise hand

Keep input concise so others have time to participate

Also make use of CHAT function

Actively listen to others, seek to understand perspectives

Offer ideas to address questions and concerns raised by others

Hold questions until after presentations

* Chat Functions

LA100

The Los Angeles 100% Renewable Energy Study

The Last Ten Percent: The Role of In-Basin Generation

Paul Denholm

May 21, 2020

LA100 Advisory Group Meeting #11

LA DWP Los Angeles Department of Water & Power

NREL Transforming ENERGY

Outline

- Planning for **peak capacity**—from historic to 100% RE systems
- **Options** to provide peak capacity in 100% RE systems
- How **technology assumptions and eligibility** influence available pathways

Purpose of This Session

- Initial Run results presented in December showed sharp differences in costs across scenarios
- The cost differences stem largely from the scenarios' different pathways in going from ~90% to 100% RE
- The purpose of this session is to discuss technology options and trade-offs for this last mile

- Relevancy to first 90% RE:
  - Role of peaking plants has near term planning implications
  - Including what replaces OTC units

Planning for Peak Capacity

The First 90(ish) Percent

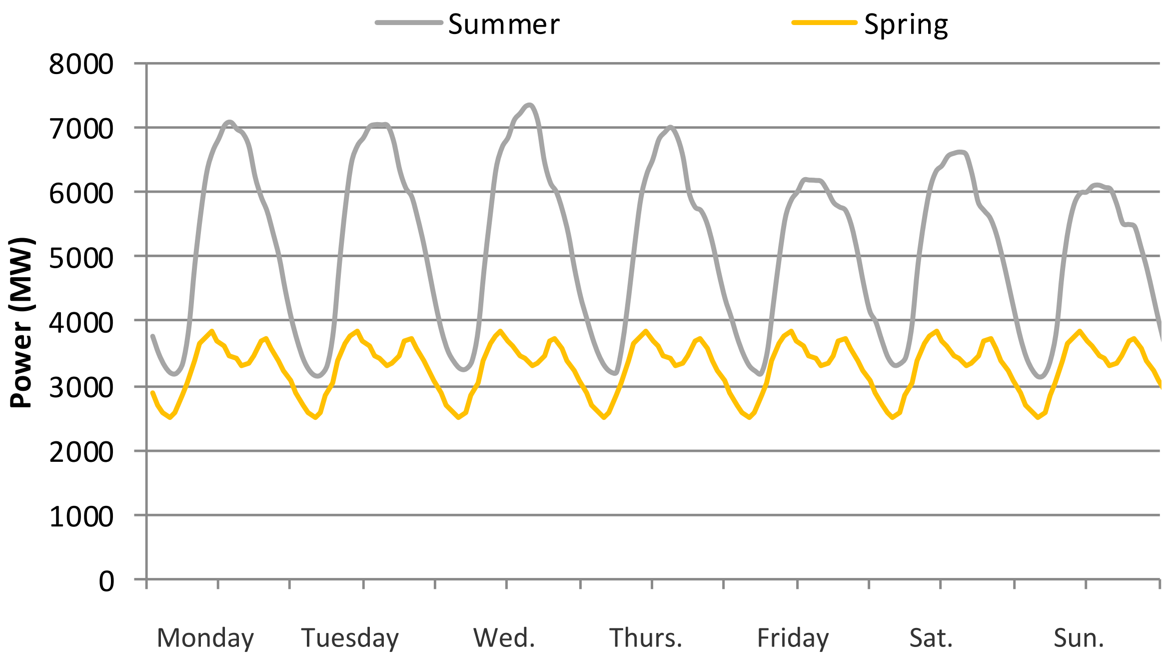
- Out-of-basin variable RE (wind, solar) and storage
- Other out-of-basin renewables (geothermal, concentrating solar power, hydro)
- In-basin solar plus storage

- This will likely achieve very deep decarbonization while remaining relatively cost competitive
- But the last ~10% is more **difficult** and **expensive**

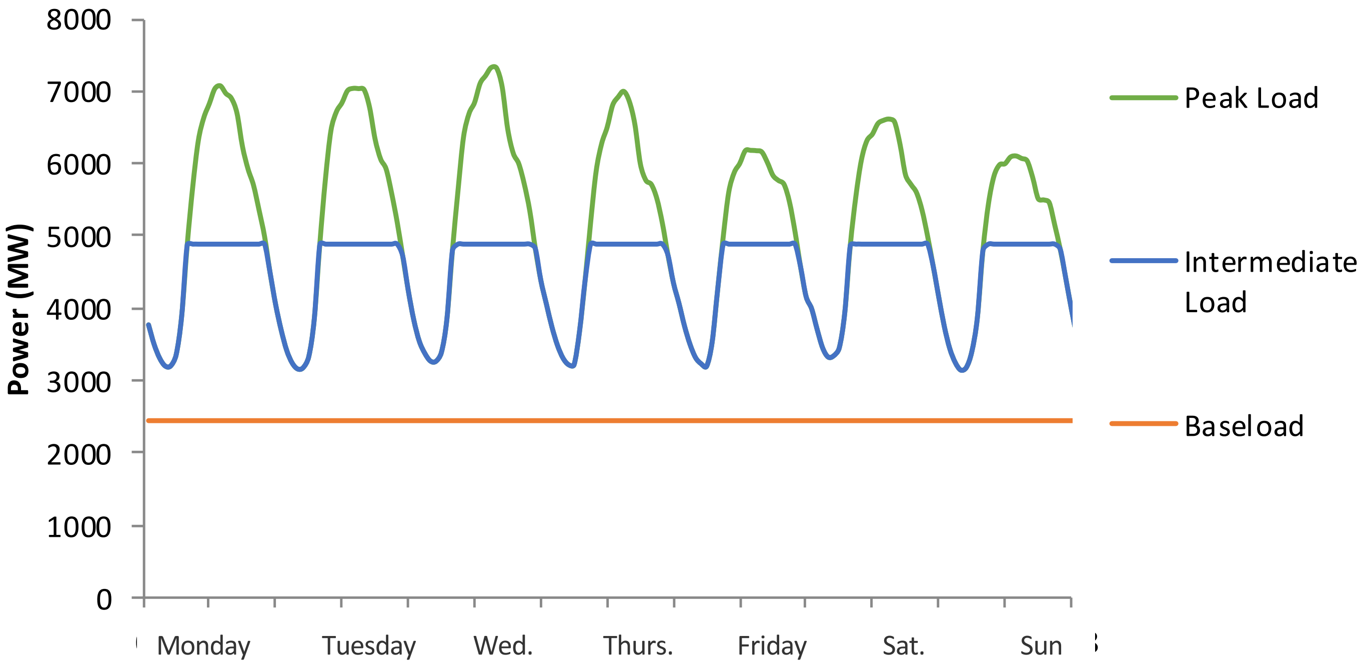
The Last 10 Percent Has Always Been Expensive

- Even in traditional systems, building plants to meet peak demand results in **higher-cost peaking electricity**
- Let’s start with a traditional perspective of planning the power system…

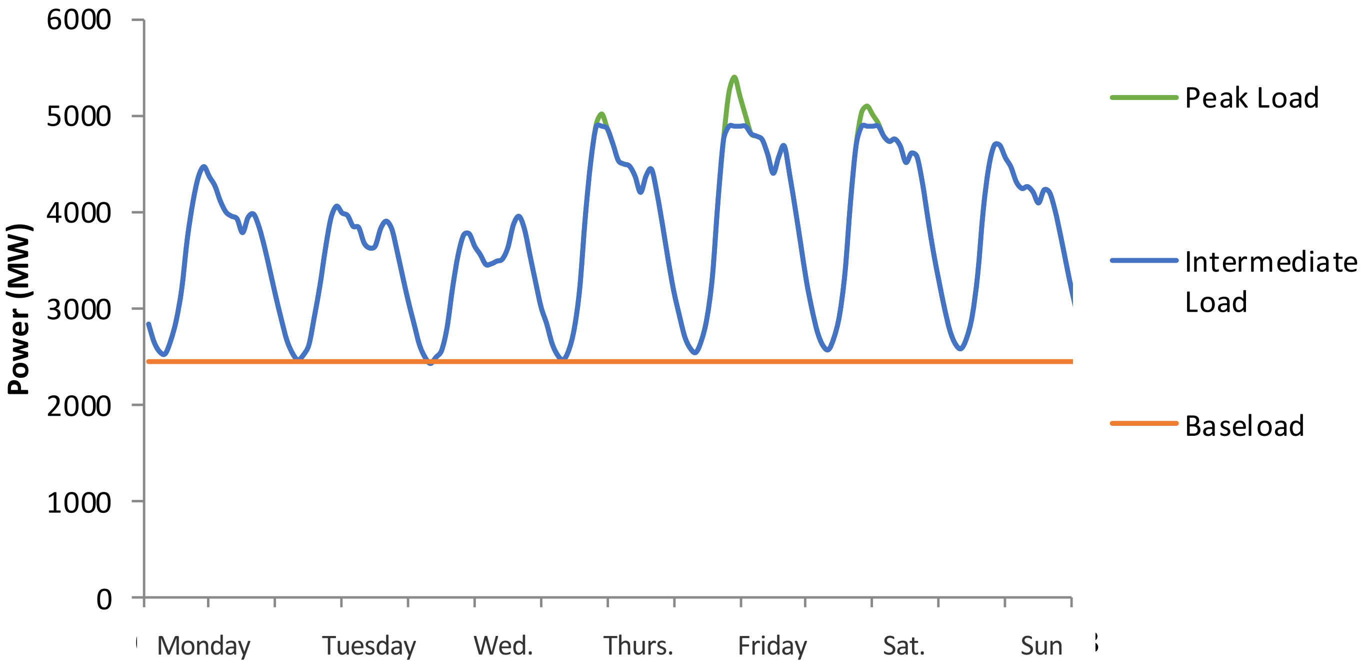
Meeting Variations in Demand



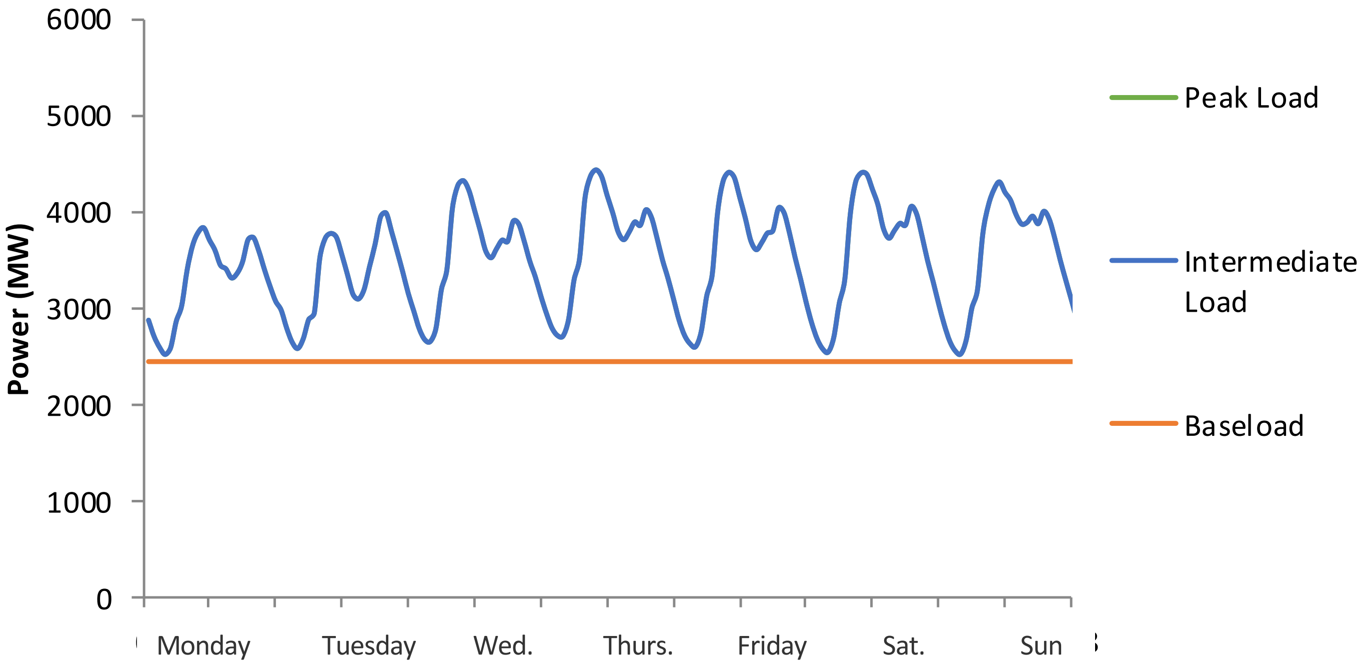
The Classical View … Peak Summer Week



But Many Weeks Don't Use Peaking Capacity Very Much

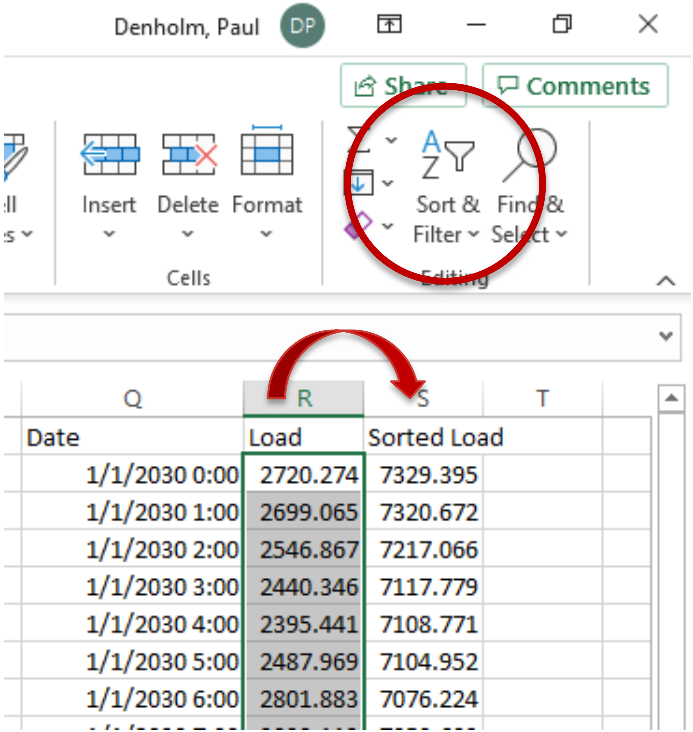


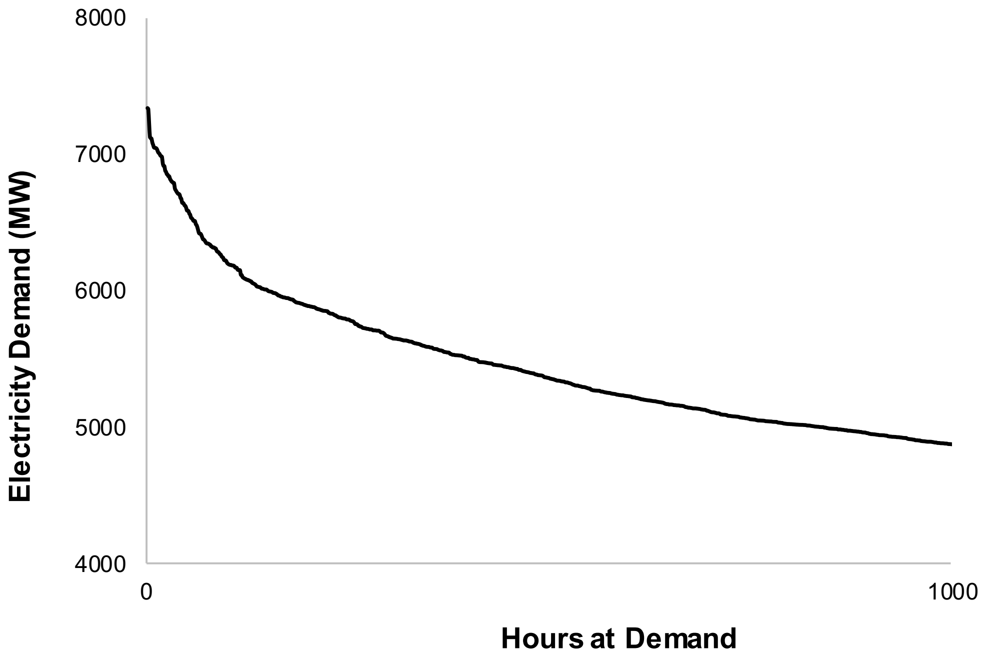
...Or At All


6000
5000
4000
3000
2000
1000
0
Power (MW)
Monday
Tuesday
Wed.
Thurs.
Friday
Sat.
Sun
Peak Load
Intermediate Load
Baseload

A Load Duration Curve Helps Us Understand This

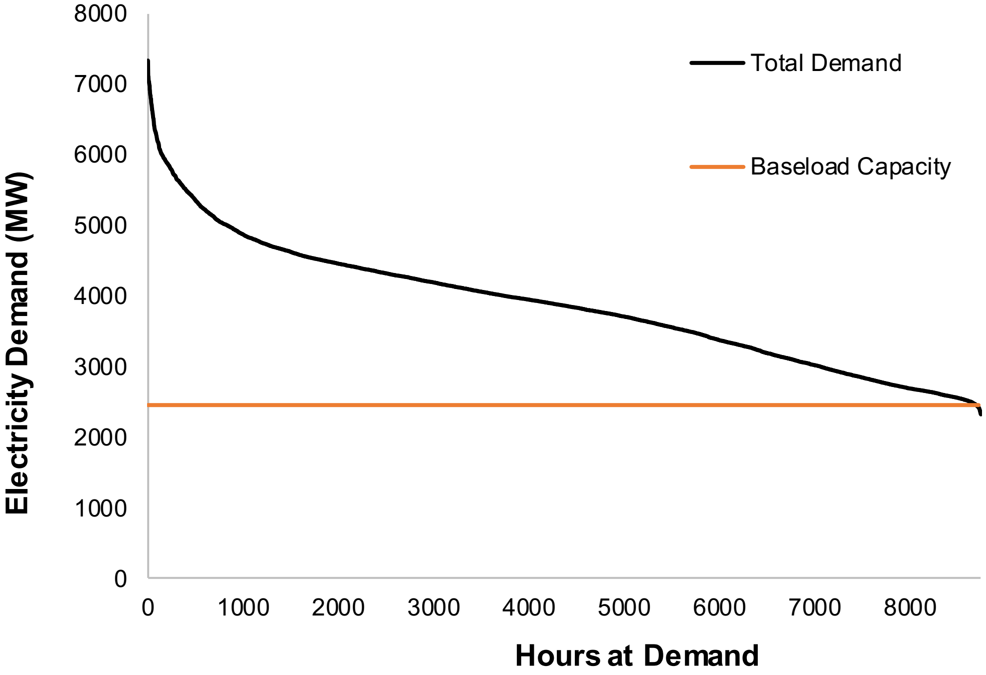
Let’s look at a load duration curve….



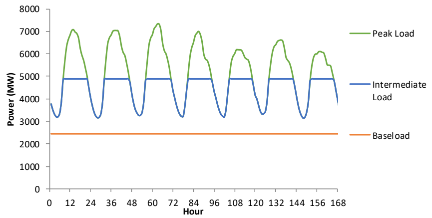


Baseload Resources in the Old Paradigm

Build 2,400 MW of "Baseload" capacity

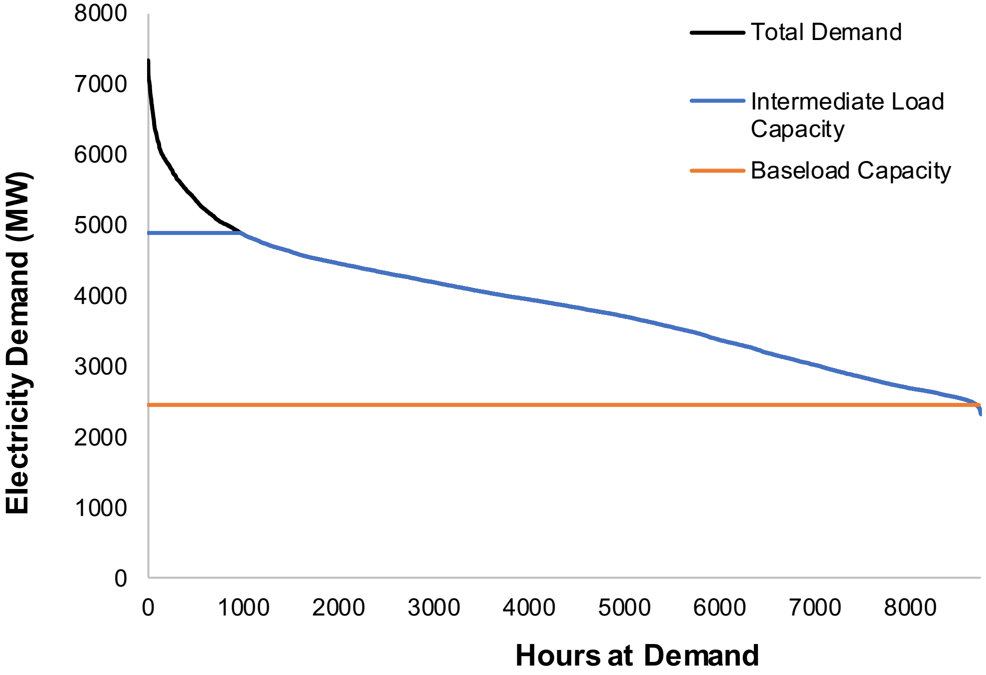


This "third" of the power plant fleet provides about 63% of total annual demand

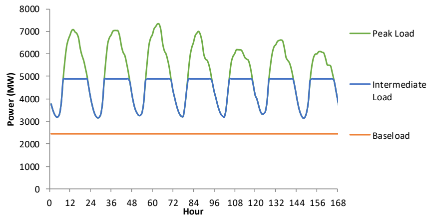


Intermediate Load Resources in the Old Paradigm

Build another 2,400 MW of "Intermediate Load" capacity

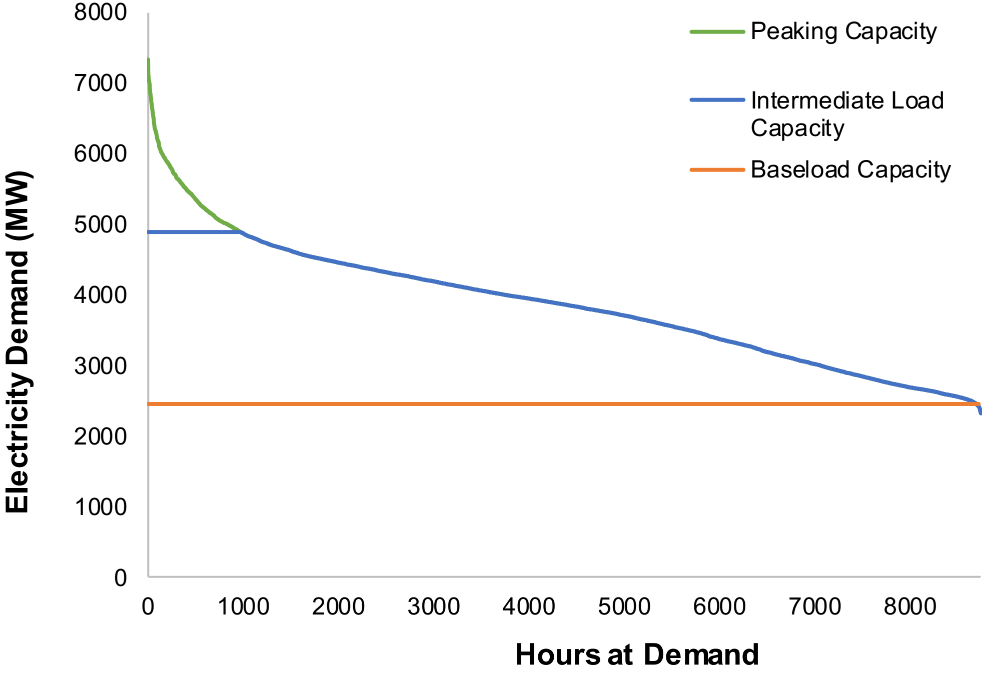


This "third" of the power plant fleet provides about 35% of total annual energy demand

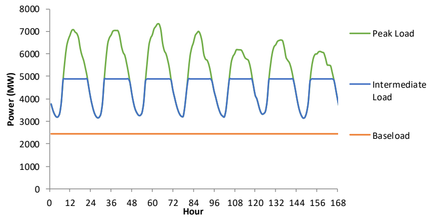


Peak Load Resources in the Old Paradigm

Build another 2,400 MW of "Peaking" capacity



This "third" of the power plant fleet provides about 2% of total annual energy demand



Bottom Line in the Traditional Paradigm

- It takes **half** of traditional capacity to provide 90% of a system's energy, and the **other half** to provide the last 10%
- This also has implications for transmission and distribution system **costs**

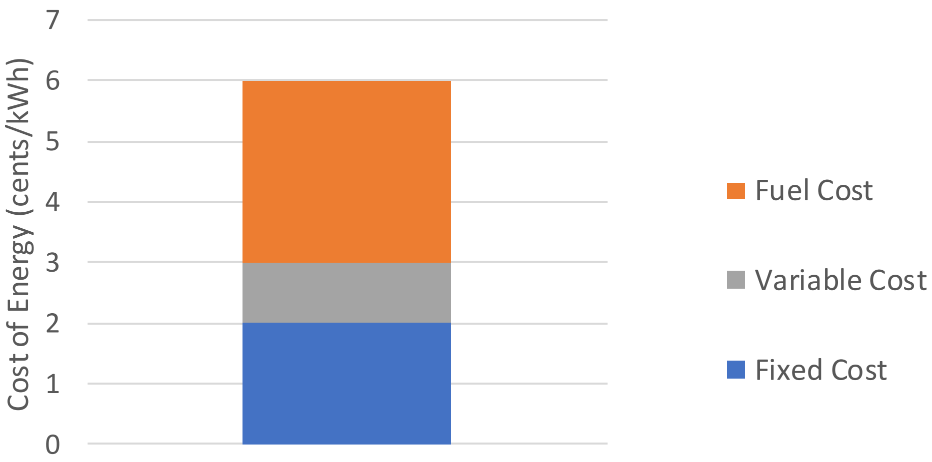
- There are lots of caveats, of course
- Traditional peaking capacity provides backup for maintenance of other units—but it still has significant cost implications

Peaking Plant Cost – It's All About Utilization…

- The average utilization (capacity factor) of plants providing the last 10% of LADWPs energy is about **11%**

- How much would Starbucks have to charge for a cup of coffee if it could only be open 3 hours per day?
  - It would have to cover all its **fixed costs** (rent, equipment) during this period

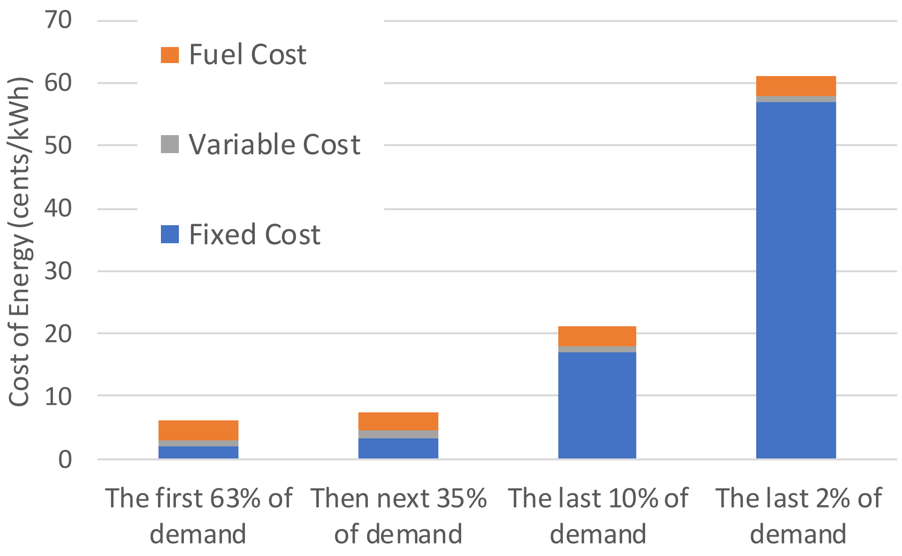
Baseload Power Plant Economics



Example scenario:

A 100 MW gas-fired power plant costs LADWP $15 Million per year (fixed costs). If they run it at 90% capacity factor, LADWP needs to charge about 2 cents per kWh to recover the fixed costs.

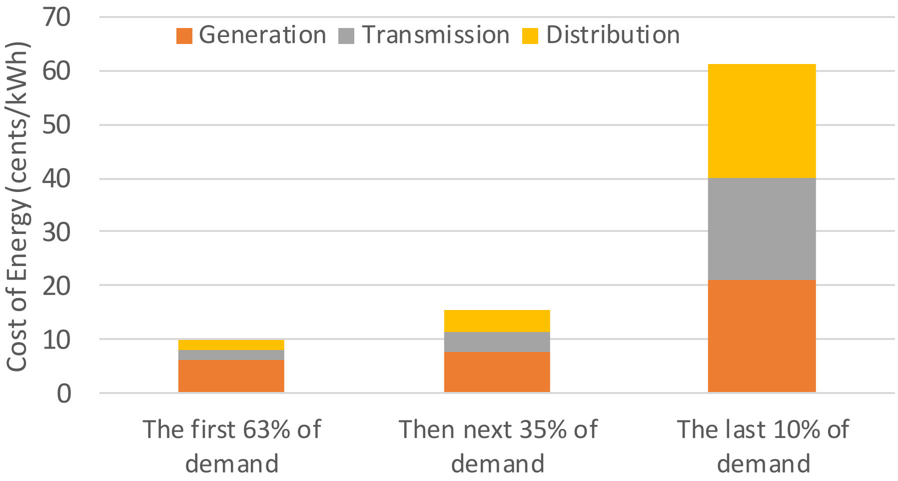
The Cost of Peaking Energy



At a 10% capacity factor, LADWP must recover all its fixed costs by charging **17 cents/kWh**

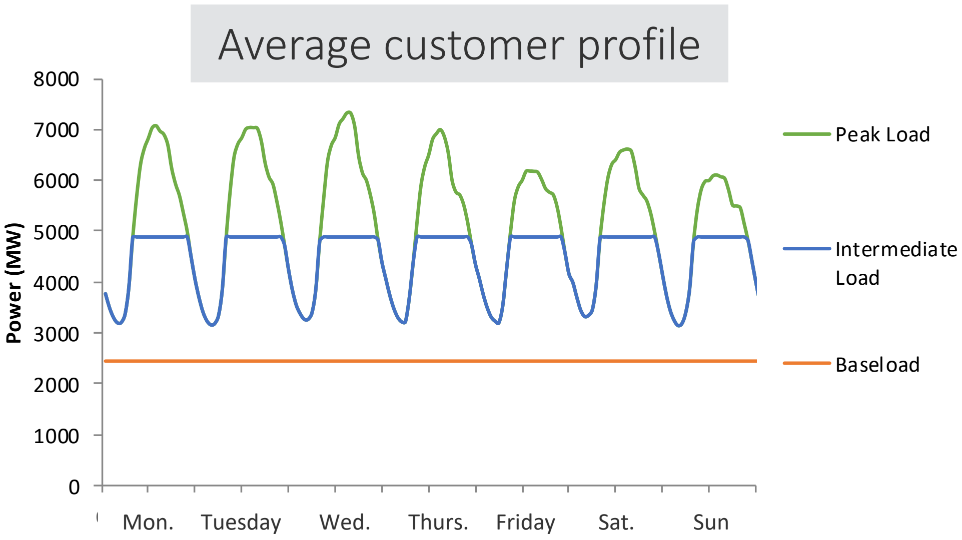
And meeting the **last 2%** of energy demand costs **57 cents/kWh** to meet fixed generation costs

The Cost of Peaking Energy



And the same applies to transmission and distribution

Implications for an Average Customer



- Uses 1,100 kWh/month for a total bill of $220 based on an average rate of 20 cents/kWh
- 440 (40%) "baseload" kWh at 10 cents/kWh ($44)
- 495 (50%) "intermediate load" kWh at 15 cents/kWh ($85)
- 165 (10%) "peak" kWh at 47 cents/kWh ($67)
- More than a third of your bill comes from the 10% of your energy use
- **But the customer doesn't see the actual impacts in flat rates, so no incentive to provide load flexibility**

Enabling Load Flexibility?

- The LA 100% RE transition provides an opportunity to address **flexibility of demand**
- Achieving 100% RE could require widespread deployment of new technologies including communication that could support demand flexibility
  - Behind-the-meter storage, EV charging
- Demand could provide additional flexibility to integrate RE at **lowest cost**

We Don’t Expect Load Flexibility to Solve the Problem

- Still high demand during hot summer afternoons
- Only so much energy can be shifted?

- So we still need **supply-side solutions**

Questions?

Up Next:

- Options to Provide Peak Capacity in 100% RE Systems
- Technology Eligibility by Scenario

Options to Provide Peak Capacity in 100% RE Systems

With 100% RE, Meeting Peak Periods Is More Economically and Technically Challenging Compared to Fossil Fuels

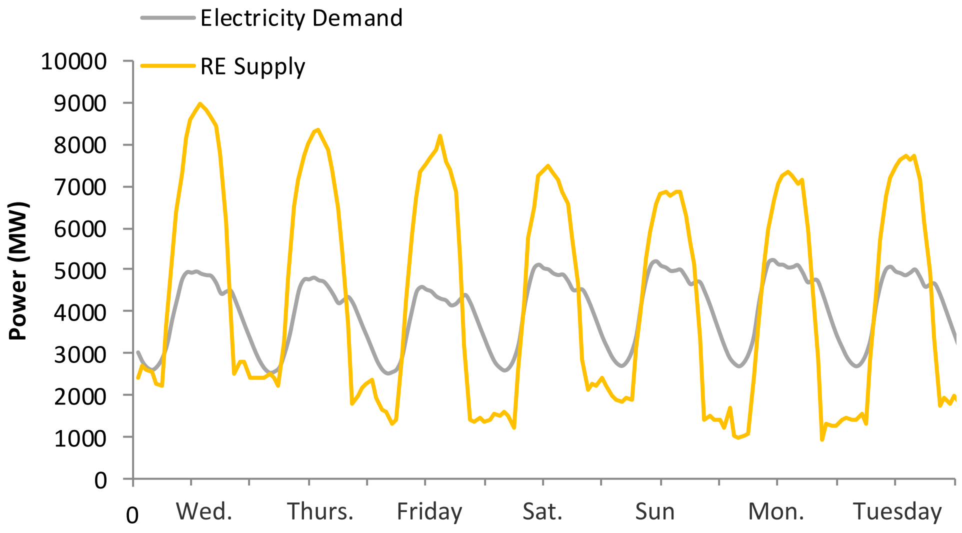
- As before:
  - Low utilization of assets built to meet the remaining demand → higher costs per kWh
- But with the added challenge of 100% RE:
  - A **limited number of resources** that can meet demand
  - Wind and solar are not necessarily available when needed

Three Supply-Side Challenges of a 100% RE System

1. When there **isn't enough** RE
2. When we cannot get it **into the basin**
3. When we cannot get it to the **right places** in basin

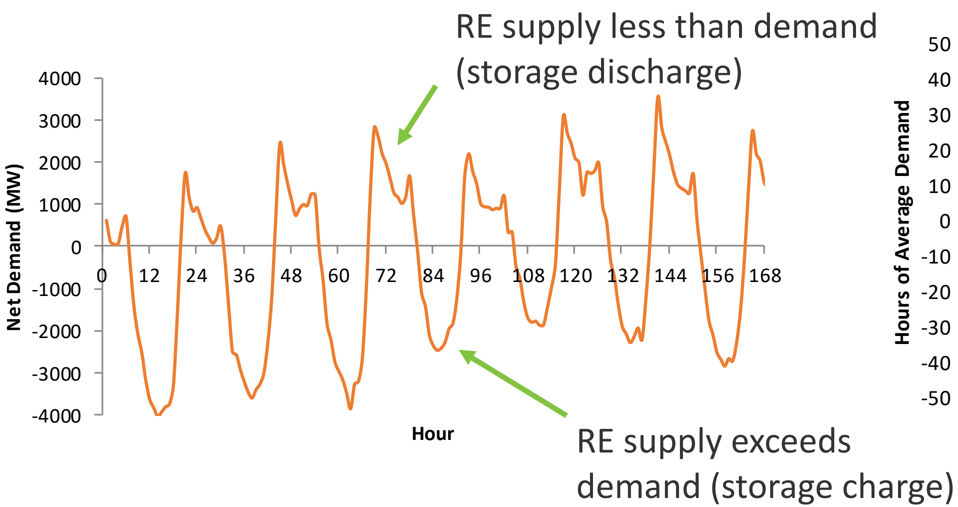
Challenge 1 – Low RE Resource

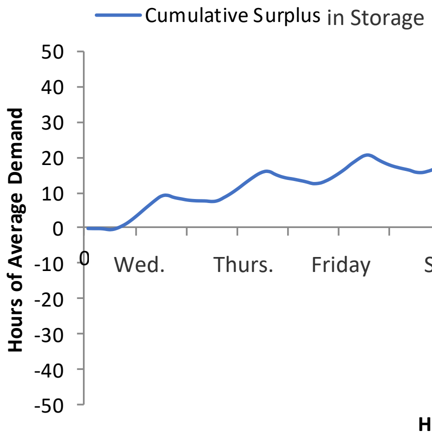
What we want to see: this nice sunny week in July



Challenge 1 – Low RE Resource

We can balance this net demand with diurnal (day-to-night) shifting technologies

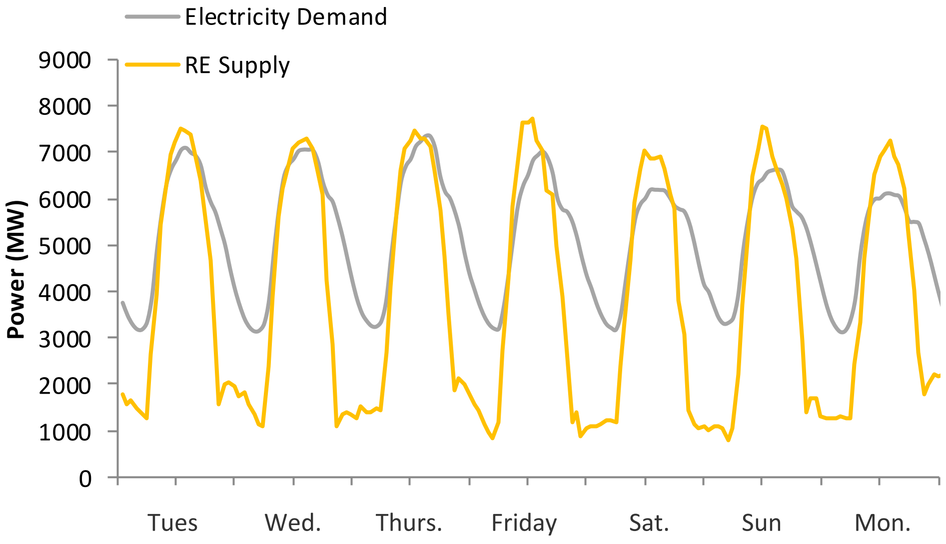




Example week has a positive balance in the storage bank

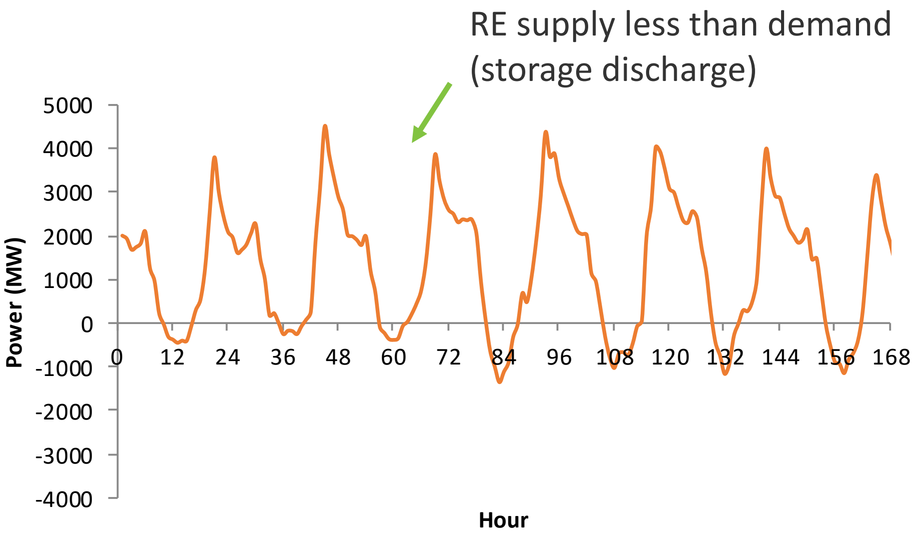
Challenge 1 – But Periods of Extended High Demand

It's nice and sunny, but there isn't very much wind, and demand is very high

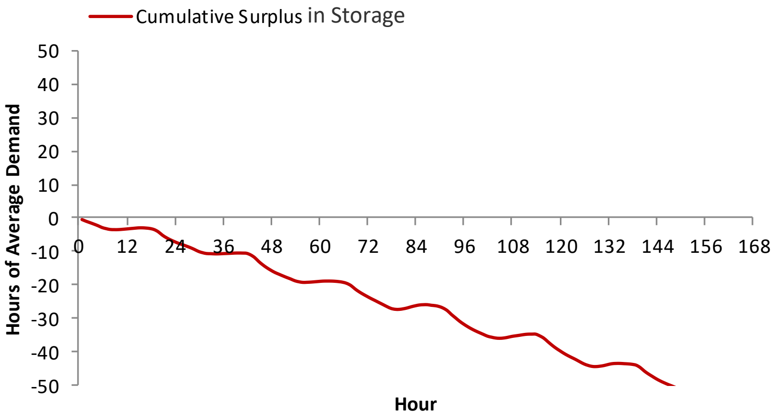


Challenge 1 – Low RE Resource

There isn't enough energy to charge our storage

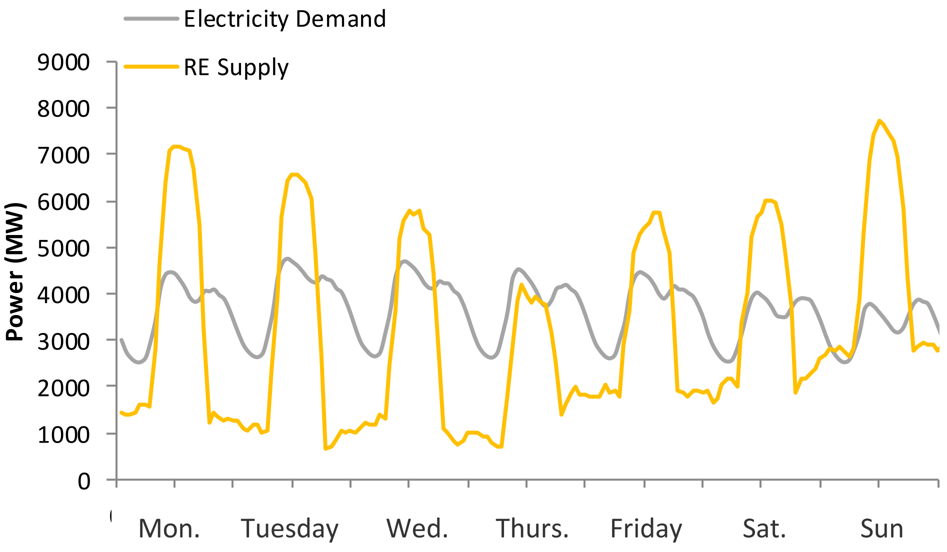


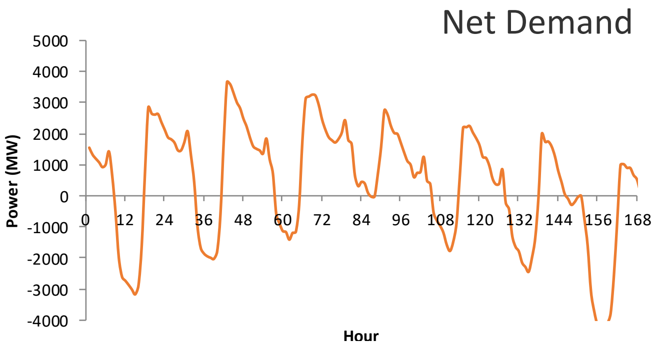
Net Demand

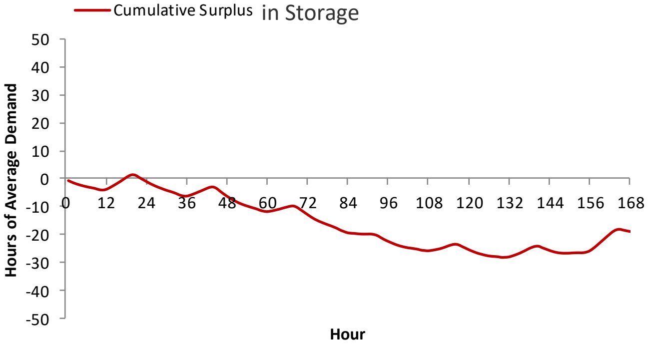


Storage "in the bank"

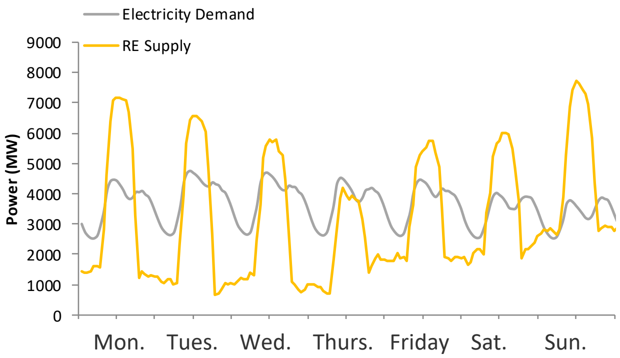
Challenge 1 – This Also Occurs During Lower Demand Periods

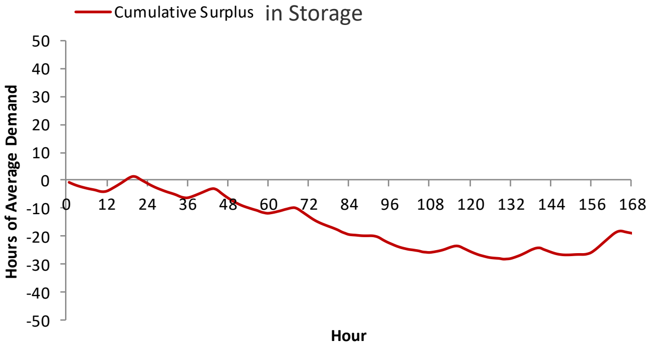




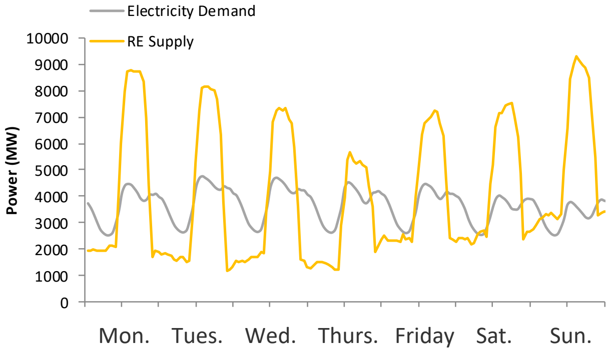


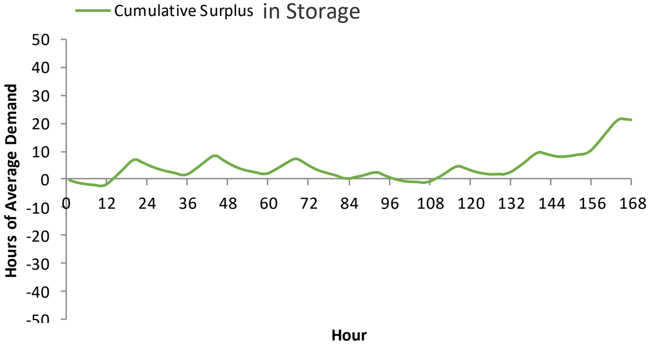
Can’t We Just Build More Wind and Solar?





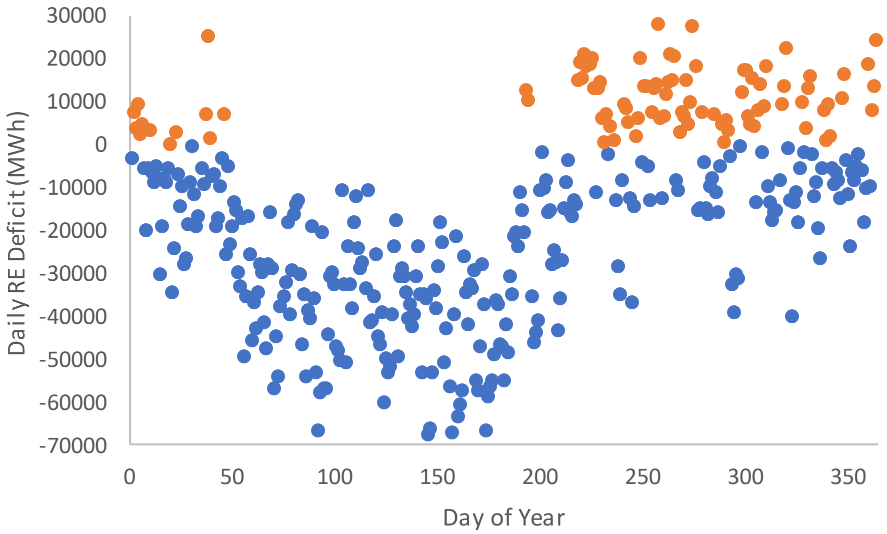
We can throw more PV and batteries at the problem





But we return to the utilization problem…

Can’t We Just Build More Wind and Solar?



We don’t really need more **energy**

We need **capacity**

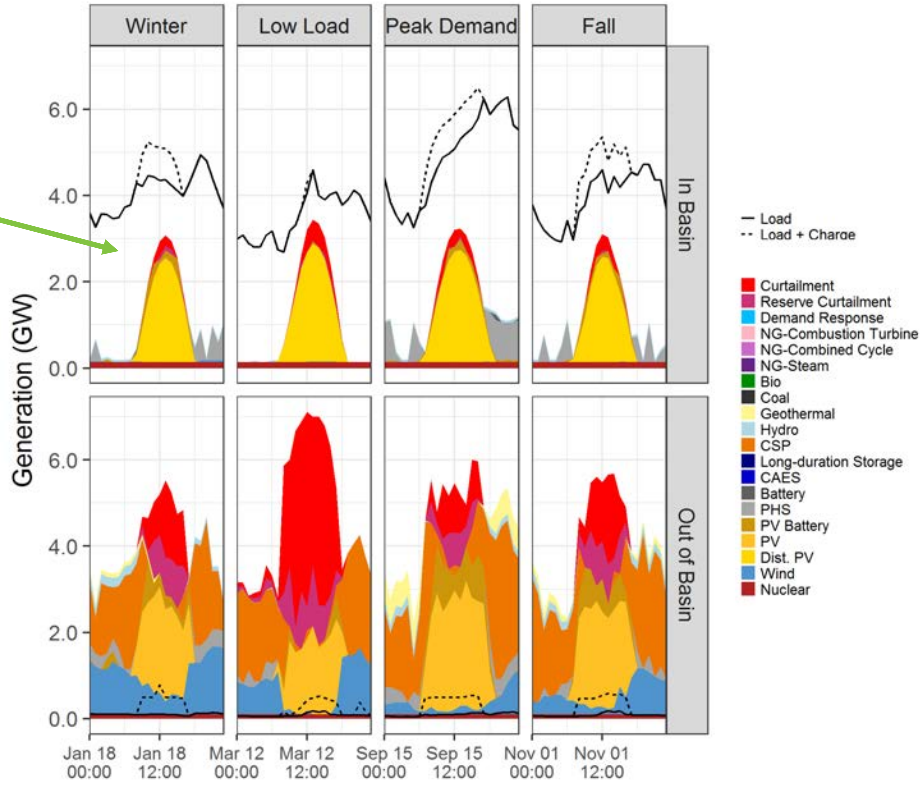
The utilization of these additional RE resources will be very low (only a few days per year)

Takeaways for Challenge #1

1. It is technically possible but **economically difficult** to get to 100% relying solely on wind, solar and traditional storage (12 hours or less capacity)
2. There are a few days where we don't have enough supply. If relying on additional solar and wind, they would have a **low utilization rate**, and therefore high cost per kWh
3. But all this depends on **transmission access**, which may be an even bigger challenge

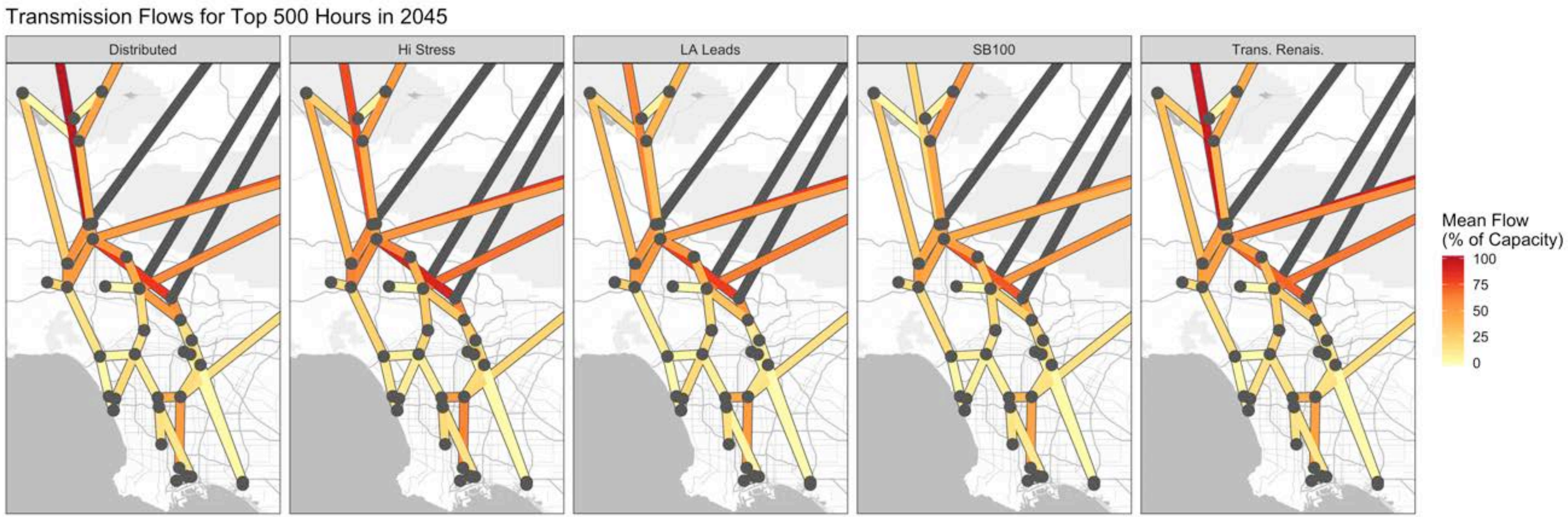
Challenge 2 – Out-of-Basin Transmission

During certain periods we are deriving a large fraction of total demand from out-of-basin resources



Challenge 2 – Out-of-Basin Transmission

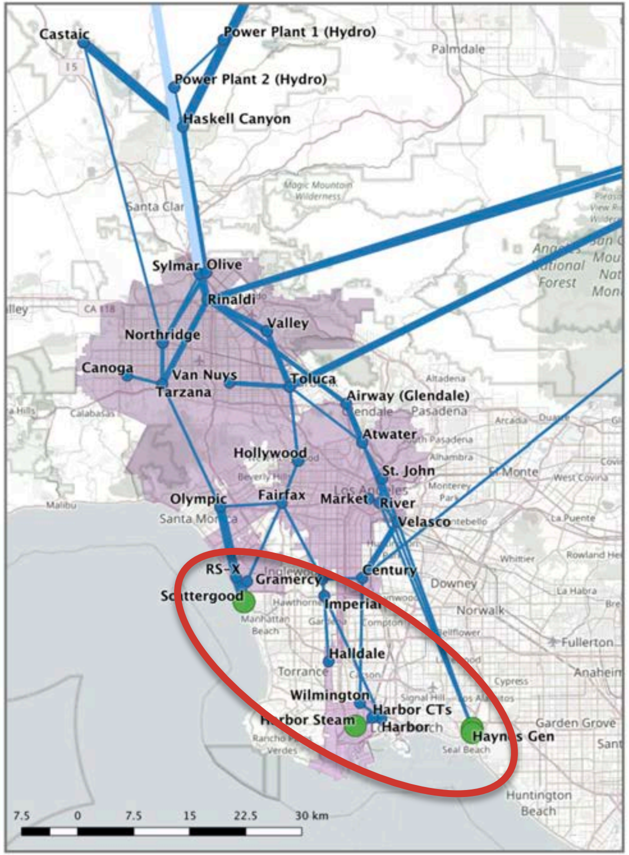
Leading to large flows on the existing transmission networks



Takeaways for Challenge #2

1. Sometimes transmission **breaks**
2. We either need **new transmission for out-of-basin resources**, or **something in basin** to replace out-of-basin resources for a few days

Challenge 3 – In-Basin Transmission



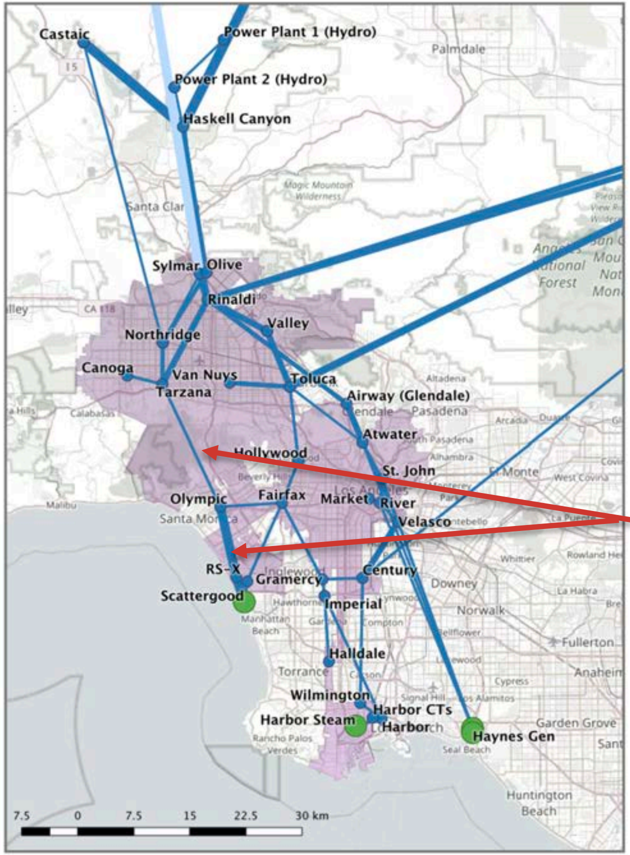
Transmission from the north

The LADWP transmission network was designed in part around power plants at specific locations in the basin.

Transmission limits/outages can be addressed by running generators in the southern part of the system (at OTC sites)

Existing generators in the south

Challenge 3 – In-Basin Transmission



Outages of in-basin transmission make it difficult to meet load in the South

Even without fires, there are still transmission outages for maintenance. (Yes, there are moving parts in the transmission system!)

Takeaway for Challenge #3

It may be difficult to deliver energy to all points within the basin without **new transmission or in-basin generation at specific locations**

Characteristics of an Ideal Solution

We likely need something in-basin that can address all three challenges

1. Can site *in basin*
   – Avoids dependencies on transmission from out of basin
2. Can site in *specific locations* in basin
   – System was designed around OTC sites, so can site there, but would like even greater flexibility
3. Can operate for *extended periods* (days or more)
4. Renewable
5. Can utilize off-peak renewables to address seasonal mismatch

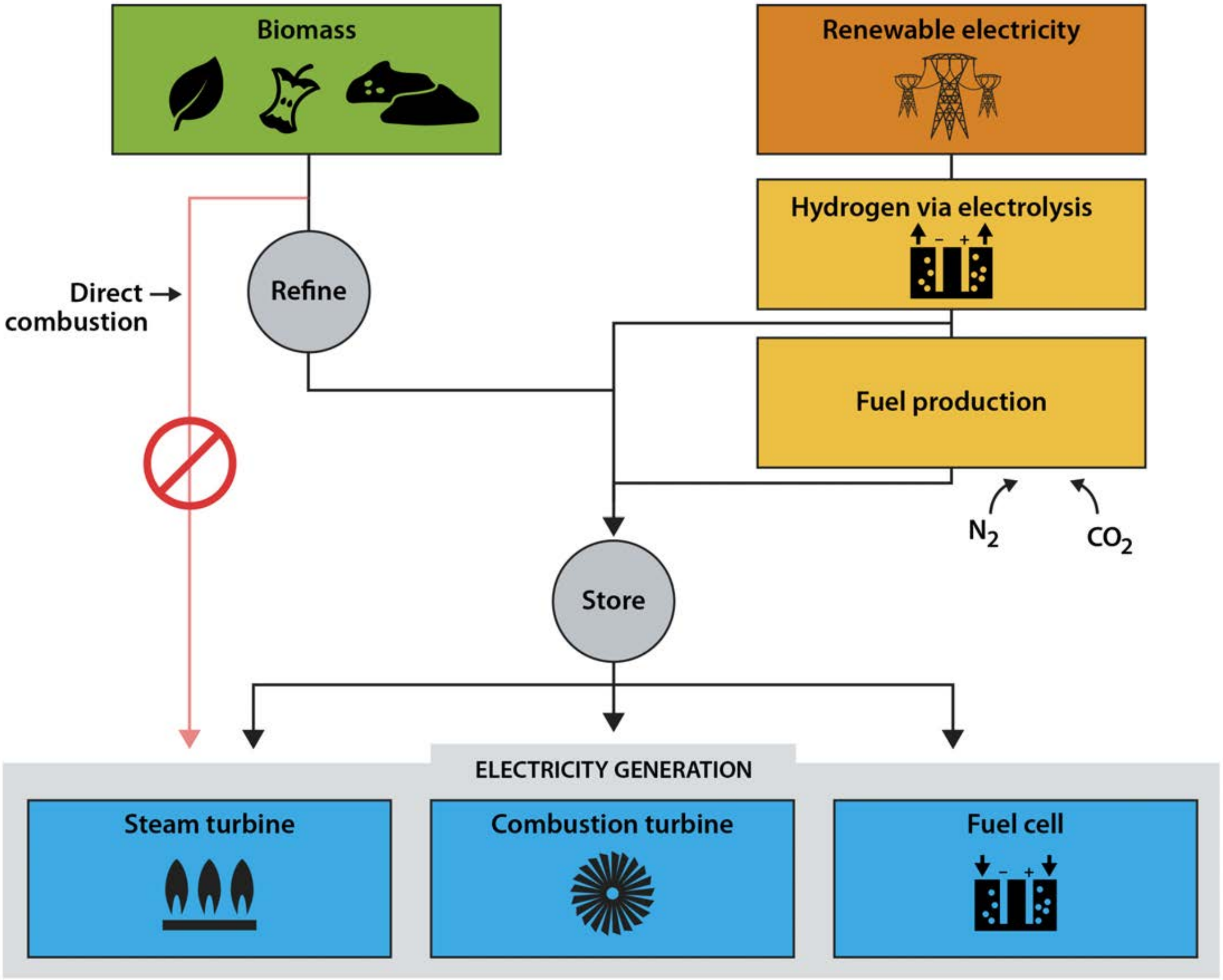
Possible Solutions We Are Not Considering

1. Extended, multi-day demand response
   – We like short-duration demand response and think it is underexploited
   – Multi-day demand response (shutting down certain industries) is unexplored, and while it might be cost effective, we aren’t evaluating it
2. Solid biomass combustion

The Solution Framework in Three Parts

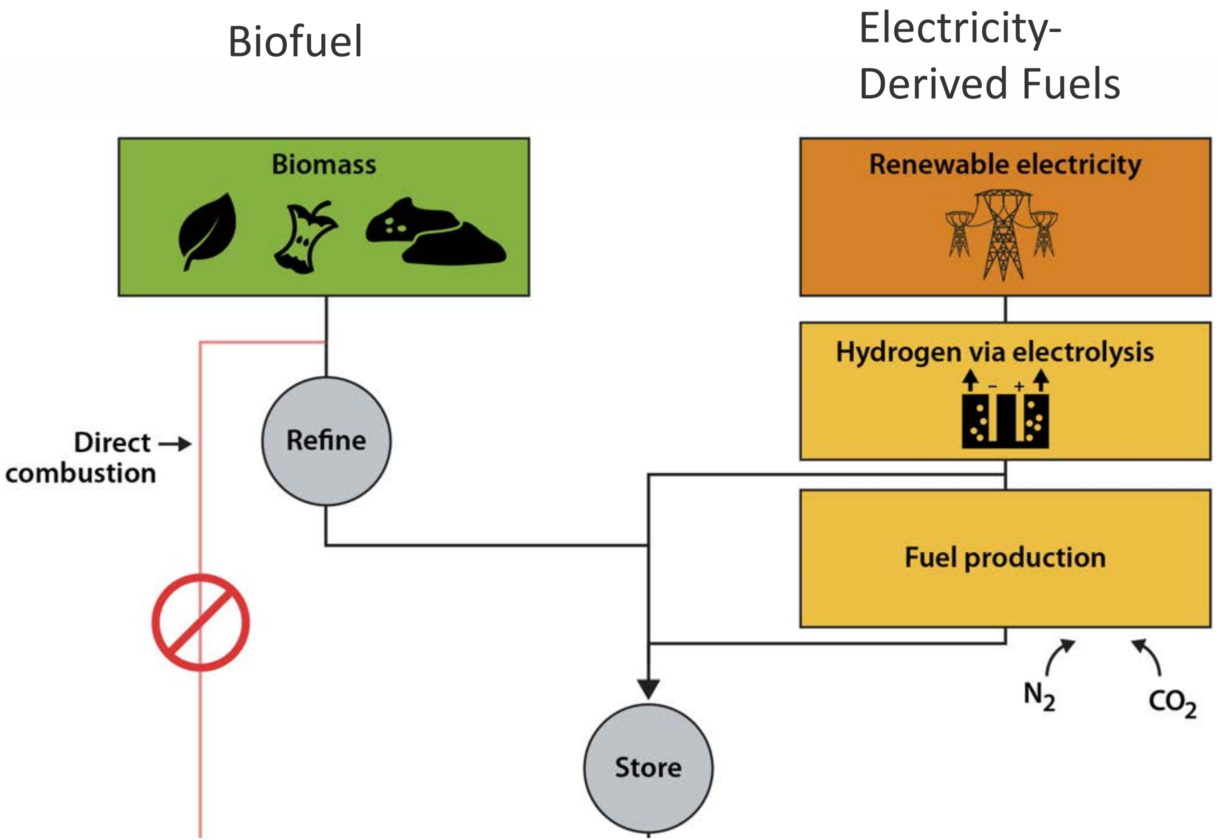
1. Producing a storable, renewably derived liquid or gaseous fuel
2. Storing and delivery
3. Converting this fuel into electricity

Pathways Overview



Making a Storable Fuel:

Two General Options

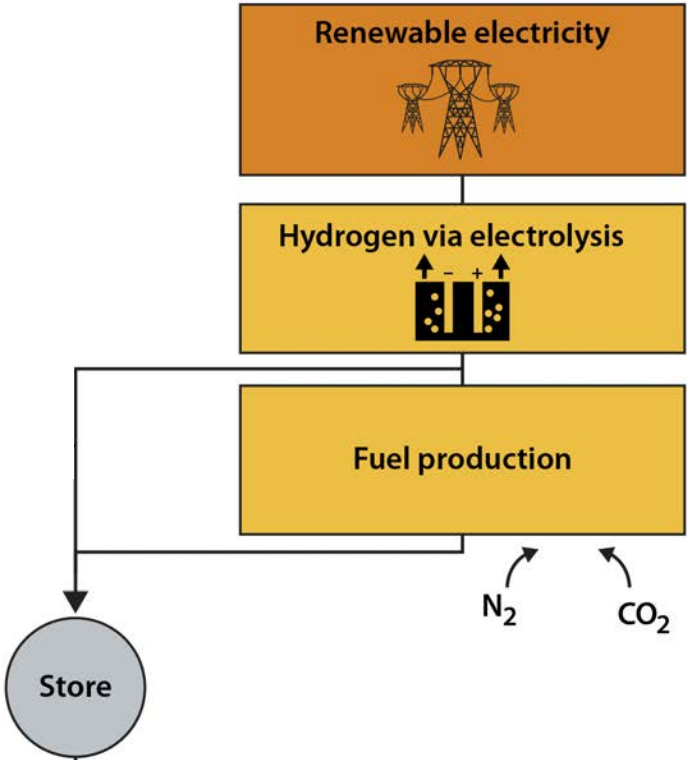


Biofuel Pathways

1. Available now
2. Two main pathways
   – Refined storable liquid biomass (ethanol, biodiesel)
   – Digester biogas (methane – can use existing pipelines)
3. A solution for LA, but not California or the U.S.
   – Probably not enough supply, especially with competition from transportation sector
4. Does not utilize off-peak RE (electricity)

Renewable Electricity to Fuel

- First, use RE to split water and make hydrogen
- Then store the hydrogen and use it later to make electricity
- And/or turn the hydrogen into something else easier to store and transport
  - Natural gas (methane)
  - Ammonia
  - Liquid hydrocarbons

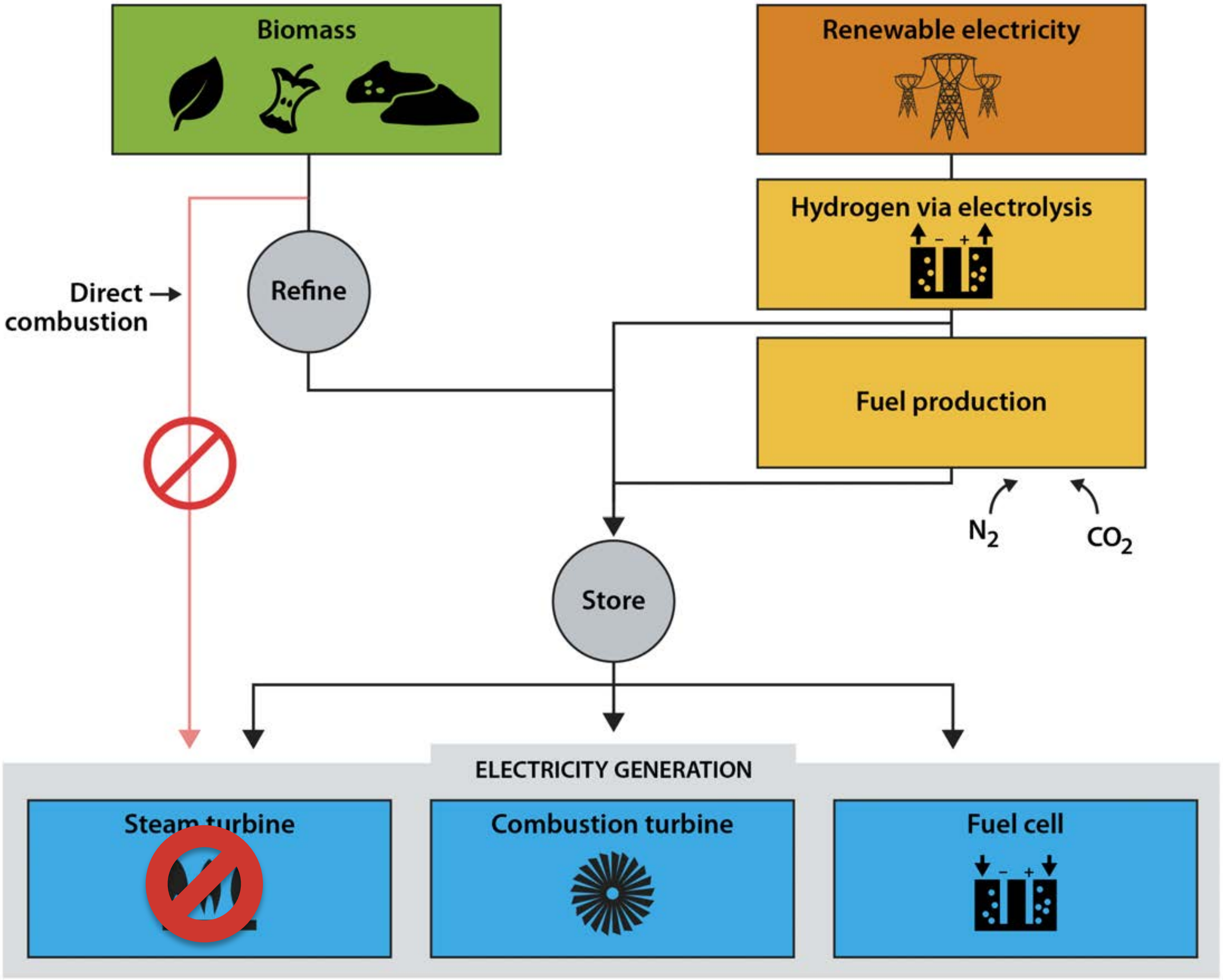


Storing and Delivery

1. Gas
   - Underground storage may be necessary
   - New pipeline infrastructure for hydrogen

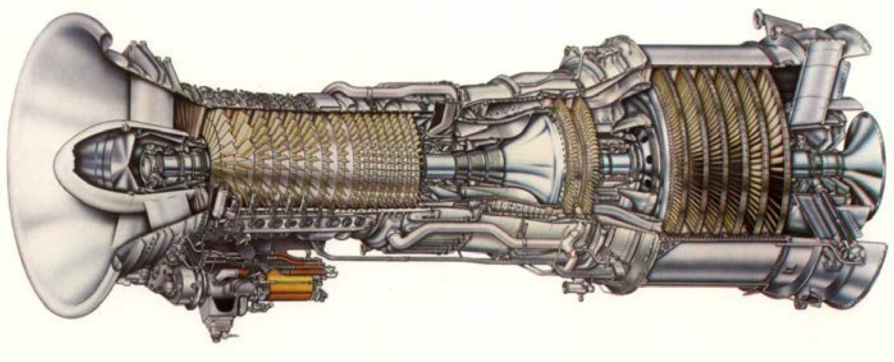
2. Liquids
   - Multiple delivery and storage options

Conversion Back to Electricity: Three Options



Combustion Turbine

- Essentially a jet engine like used on airplanes
- About 30% more efficient than steam plants (like OTC units)
- Some NOx emissions
- No water use



General Electric LM2500 Gas Turbine

Non-Combustion (Fuel Cells)

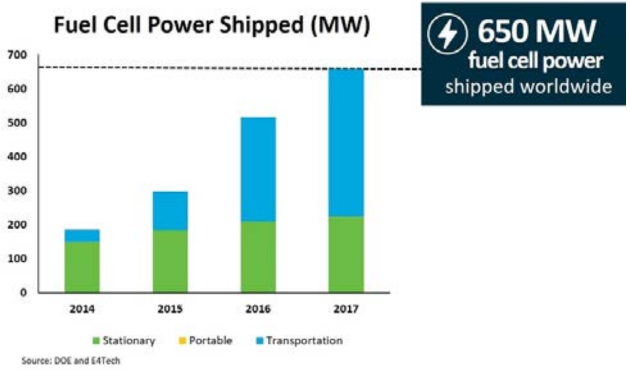
- A battery-like device that uses a fuel
- Similar efficiency to a combustion turbine
- No NOx emissions or water use

Fuel Cell Types

Two main types:

1. Proton exchange membrane (hydrogen or reformed fuels)
   - This is the type used in cars
2. Solid oxide fuel cell (biogas or synthetic methane)
   - This is the type being deployed in limited numbers at banks and other locations for backup power
   - Typically used with natural gas

Compare to 30,000 MW of gas turbines in 2018 just for power generation

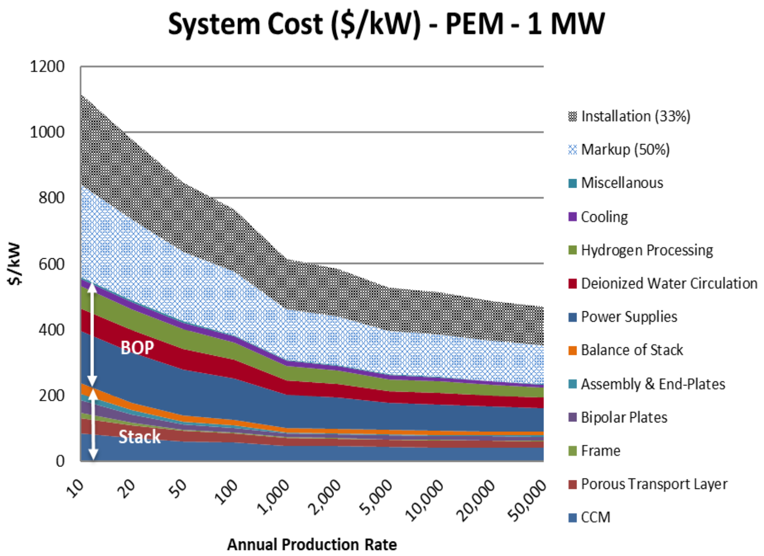


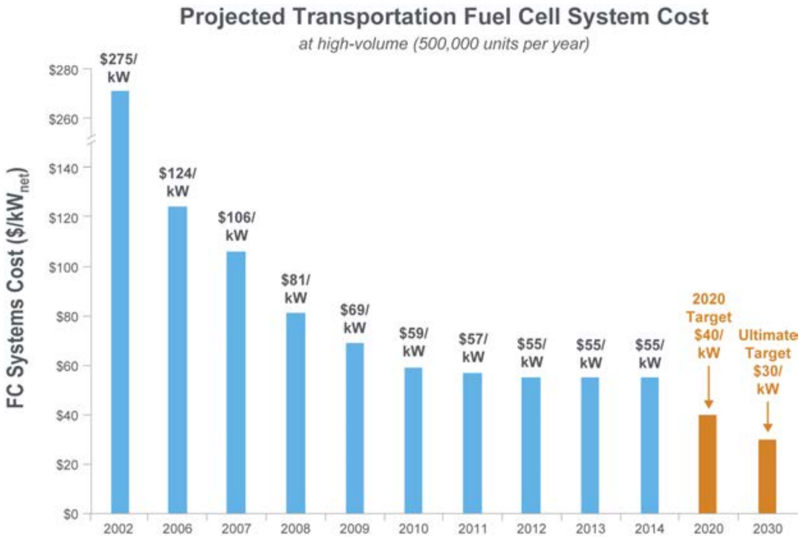
Combustion Turbine vs Fuel Cell

	Combustion Turbine	Fuel Cell
Cost	Much Lower	Much Higher. Cost reduction potential is significant but highly uncertain
Fuel Flexibility	High – and can transition (hydrogen blends at IPP for example)	Much lower
Footprint	Large - Probably only at existing OTC site	Smaller, more flexible
Operation Flexibility	Some limits, but utilities very comfortable with rotating machines	More operational flexibility. Uses power electronics which can provide additional services
Emissions	A little NOx	None
Life	Long, well understood	Less certain

Uncertainty in Non-Combustion Based Options

Very significant uncertainty in costs of RE fuel pathways, particularly for non-combustion options. They could become very cheap if large-scale production for vehicles occurs.





Questions?

Up Next:

- Technology Eligibility by Scenario

Technology Eligibility by Scenario

Ambiguity in Scenario Matrix

As presented in September

		LA100 Scenarios								
		Moderate Load Electrification				High Load Electrification (Load Modernization)				High Load
		SB100	LA-Leads, Emissions Free (No Biomass)	Transmission Renaissance	High Distributed Energy Future	SB100	LA-Leads, Emissions Free (No Biomass)	Transmission Renaissance	High Distributed Energy Future	High Load Stress
	2030 RE Target	60%	100% Net RE	100% Net RE	100% Net RE	60%	100% Net RE	100% Net RE	100% Net RE	60%
	Compliance Year for 100%	2045	2035/2040	2045	2045	2045	2035/2040	2045	2045	2045
Technologies Eligible in the Compliance Year	Biomass	Y	No	Y	Y	Y	No	Y	Y	Y
	Biogas	Y	No	Y	Y	Y	No	Y	Y	Y
	Electricity to Fuel (e.g. H2)	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Fuel Cells	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Hydro - Existing	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Hydro - New	N	N	N	N	N	N	N	N	N
	Hydro - Upgrades	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Natural Gas	Yes	N	N	N	Yes	N	N	N	Yes
	Nuclear - Existing	Y	Y	No	No	Y	Y	No	No	Y
	Nuclear - New	N	N	N	N	N	N	N	N	N
	Wind, Solar, Geo	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Storage	Y	Y	Y	Y	Y	Y	Y	Y	Y
Repowering OTC	Haynes, Scattergood, Harbor	N	N	N	N	N	N	N	N	N

Fixes:

- **Biomass** was listed as allowed, which we do not allow in any scenario *as a solid*
- **Biogas** → Biofuel (to include liquid)

Ambiguity:

- Electricity to Fuel (e.g. H2)

Correct in that allowed in all scenarios, but the scenario matrix does not address what we can do with the fuel to convert to electricity?

Same Assumptions (As We Understand Them)—Revised for Clarity

As presented today

		LA100 Scenarios								
		Moderate Load Electrification				High Load Electrification (Load Modernization)				High Load Stress
		SB100	LA-Leads, Emissions Free (No Biofuels)	Transmission Renaissance	High Distributed Energy Future	SB100	LA-Leads, Emissions Free (No Biofuels)	Transmission Renaissance	High Distributed Energy Future	SB100
	RE Target in 2030 with RECs	60%	100%	100%	100%	60%	100%	100%	100%	60%
	Compliance Year for 100% RE	2045	2035	2045	2045	2045	2035	2045	2045	2045
Technologies that do not vary in eligibility across scenarios	Solid Biomass	N	N	N	N	N	N	N	N	N
	Fuel Cells	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Hydro - Existing	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Hydro - New	N	N	N	N	N	N	N	N	N
	Hydro - Upgrades	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Nuclear - New	N	N	N	N	N	N	N	N	N
	Wind, Solar, Geothermal	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Storage	Y	Y	Y	Y	Y	Y	Y	Y	Y
Technologies that do vary	Biofuel Combustion	Y	No	Y	Y	Y	No	Y	Y	Y
	RE-derived Fuel Combustion (e.g., hydrogen)	Y	No	Y	Y	Y	No	Y	Y	Y
	Natural Gas	Y	No	No	No	Y	No	No	No	Y
	Nuclear - Existing	Y	Y	No	No	Y	Y	No	No	Y
Repowering OTC	Haynes, Scattergood, Harbor	N	N	N	N	N	N	N	N	N

Maintaining "Emissions Free" scenario as no combustion:

- **RE-derived Fuel Combustion (e.g., H2)** is not allowed, even at IPP

But was that the intention of the Advisory Group? We want to discuss.

Scenario Eligibility

1. Combustion
   (RE-derived fuel)

SB100
High Distributed Energy Future
Transmission Renaissance

2. Non-Combustion
   (Fuel Cells)

All Scenarios, including
LA Leads/Emissions Free

Cost Implications

- Currently, combustion-based options are lower cost
- We don’t know if/when costs will be lower for non-combustion based pathways
  - By 2030, cost differences between biofuel combustion and fuel cells could total $1-2 billion for the needed capacity
  - By 2045, non-combustion alternatives may be more cost-competitive, but there is still significant price uncertainty

Clarifying Question for AG

- LA Leads/Emissions Free was unambiguous on biofuels, which are excluded.
- What about combustion of RE-derived fuels such as hydrogen?
  - Out-of-basin options like IPP?
  - In-basin options, such as at OTC sites?

If include:

- Lower cost
- Potentially lower transmission risks
- Some NOx

If don't include:

- Increased reliance on out-of-basin wind/solar capacity, transmission, and/or more expensive fuel cells

Questions?

The Los Angeles 100% Renewable Energy Study