Decarbonized Electric Power Systems: Some Preliminary Results

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Harvard Kennedy School
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We Have Begun a Journey Toward Decarbonization

• Driven by subsidies for renewables, especially wind & solar (VERs)
  • Substantial federal ITC (solar) and PTC (wind) have had a major impact
  • 29 states plus DC & PR have RPSs, 3 others have clean energy standards
  • Innumerable other state & local programs, including net metering
  • Small-scale, inefficient, behind-the-meter (BTM) solar has been treated particularly well

• Growth in VERs has created operational challenges
  • Expensive BTM solar heavily subsidized (esp. by net metering), quick to build, not dispatchable
  • Solar output varies substantially but fairly predictably on diurnal/seasonal time-scales,
  • But outputs of both solar & wind vary substantially & stochastically around diurnal/seasonal averages – they are *intermittent*
What Rooftops Can Do: Oahu (Hawaii), 2008-2018
(Population ↑ 4.6%, Load ↓ 11.5%)

Source: Blue Planet Foundation, Hawaii’s Energy Report Card, 2019
Prices Are Being Distorted, Markets Are Stumbling

- Per-MWh VER subsidies (RPS regimes & wind PTCs) are financed by raising per-kwh retail rates, even though zero-SRMC VERs lower system SRMC
  - “It costs $0.30/kwh to charge an EV in Honolulu even when solar is being curtailed”
  - These subsidies distort wholesale prices downward, & some thermal generators are being kept alive by administratively-determined payments outside wholesale energy markets

- Conventional capacity markets based on nameplate capacities & performance at peak times don’t work, since VER capacity is weather-dependent & stochastic
  - Non-performance penalties drive out utility-scale VER projects, which are supported by out-of-market payments, mainly from utilities with RPS obligations
  - CAISO has had to add markets for flexible capacity, i.e., gas; inconsistent with decarbonization

- Transmission has become more important (geographic averaging, connecting remote generation sites), but may be harder to build
Changes in US. Generation Capacity, 2015 – 2018

<table>
<thead>
<tr>
<th>Generator Type</th>
<th>GW Change</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Scale Wind &amp; Solar</td>
<td>40.1</td>
<td>46.5</td>
</tr>
<tr>
<td>Small (rooftop) Photovoltaic</td>
<td>9.8</td>
<td>99.9</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>30.8</td>
<td>7.0</td>
</tr>
<tr>
<td>Coal</td>
<td>-36.9</td>
<td>-13.2</td>
</tr>
<tr>
<td>Nuclear &amp; Other</td>
<td>-3.3</td>
<td>-1.3</td>
</tr>
<tr>
<td>Total Generation Capacity</td>
<td>40.5</td>
<td>3.8</td>
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Source: EIA
Going Farther Down This Bumpy Road…

- CA, HI, and 4 other states plus DC & PR have mandates for 100% clean or renewable energy in the electricity sector by 2045 or 2050

- Many other ambitious goals, e.g., 80% cut in all MA GHG emissions by 2050, which seems likely to require 100% wind & solar in electricity

- Electricity accounts for only 28% of GHG emissions, but needs to decarbonize to have clean electricity for transportation (29%), HVAC (12%), some industry (22%)

- Given support for clean energy, growing climate concern, plausible to expect pressure for nearly 100% wind & solar (plus storage) in electricity by 20XX
  - What would efficient decarbonized electric power systems look like? How would large-scale intermittency be managed?
  - Can we actually get there at politically tolerable costs?
  - What regulatory policies & market designs would be most efficient?
Renewable & Clean Energy Standards

- **Renewable portfolio standard**: 29 States + DC have a Renewable Portfolio Standard, 3 states have a Clean Energy Standard (8 states have renewable portfolio goals, 2 states have clean energy goals)

- **Renewable portfolio goal**: Includes non-renewable alternative resources

- **Clean energy standard**: Extra credit for solar or customer-sited renewables

- **Clean energy goal**: 9
The MITEI *Future of Energy Storage* Project Addresses Most of These Questions

- **Questions**: What roles would energy storage play in future efficient, decarbonized electric systems & what policies would support efficiency in such systems?
- Technical team describing *plausible* future storage technologies that could manage VER intermittency
- *Economics team* using optimization models to study *plausible* high-VER systems
  - Team includes Paul Joskow, Howard Gruenspecht, and the actual workers: Patrick Brown, Cristian Junge, Dharik Mallapragada, & Cathy Wang
  - (Mostly) greenfield, foci are 2030 and 2050; much uncertainty → tons of sensitivity analyses
  - Discussions of optimal regulation & market design for high-VER systems just beginning
- Still early days, not even a firm outline of the final report
- Will give MY TAKE on implications of what seem to be emerging general patterns
What Storage Technologies? What Costs?

• Technologies differ in costs of **power** ($/MW) & **energy** ($/MWh) [faucet v. tank], round-trip efficiency, lifetime (f(usage)), speed of response, self-discharge, O&M…
  – Also differ in technological readiness; much hype around **many** unproven technologies – e.g., CAES

• Have focused on storage technologies clearly available by 2030:
  – Lithium-ion batteries: in use (vehicles), MC(energy) high, good for ST storage (3-4 hours)
  – Pumped hydro: proven, MC(energy) low, good for MT storage (8-12 hours), **hard to expand**
  – Reservoir hydro: proven, charging is stochastic, up to seasonal storage, **very hard to expand**

• Are experimenting (with guesstimates of cost) on longer-term possibilities:
  – Flow batteries: main advantage is low MC(energy) – tank size – for MT (days) storage
  – Hydrogen: can do LT storage, but current technology is capital-intensive, so need high utilization

• Keeping our eyes on: new batteries, gravity-based, liquid air (VT), thermal, Allam Cycle…
Optimal Systems with Storage: General Results

- Classic Boiteux-Turvey result: If
  - (a) no scale economies in generation,
  - (b) no ramping constraints or costs,
  - (c) perfectly inelastic, stochastic demand,
  - (d) a single location,
  - (e) price = VLL if shortages, system MC otherwise, then

  - At the generation capacity portfolio that minimizes the expected cost of meeting any load, all technologies employed just break even; supports reliance on competition in power markets
  - But if price is capped below VLL, the efficient portfolio loses money (the missing money problem)
  - Otherwise, OK fit for a VER+gas system with enough transmission, but what about intermittency?

- Newish result (known, but apparently only by a few): Under perfect foresight (assumed in our optimization) & the assumptions above, then

  - At the cost-minimizing asset portfolio for any given time-path of load, all technologies employed, including storage, just break even; (weaker) support for reliance on competition
  - If price is capped below VLL, both generation & storage have missing money
An example: NY/NE, modeled assuming existing hydro & pumped hydro, plus storage with 2050 performance and cost projections for Li-ion

### Electrochemical storage assumptions

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<table>
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<tr>
<td>Power costs ($/kW)</td>
<td>280</td>
</tr>
<tr>
<td>(59% reduction vs. 2018')</td>
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</tr>
<tr>
<td>Energy costs ($/kWh)</td>
<td>86</td>
</tr>
<tr>
<td>(59% reduction vs. 2018')</td>
<td></td>
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<tr>
<td>Fixed O&amp;M power costs</td>
<td>6</td>
</tr>
<tr>
<td>($/kW/yr)</td>
<td></td>
</tr>
<tr>
<td>Fixed O&amp;M costs ($/kWh/yr)</td>
<td>7.5</td>
</tr>
<tr>
<td>Variable O&amp;M costs</td>
<td>1.3</td>
</tr>
<tr>
<td>($/MWh)</td>
<td></td>
</tr>
<tr>
<td>Min and max duration</td>
<td>0.25 to 30</td>
</tr>
<tr>
<td>(hours)</td>
<td></td>
</tr>
<tr>
<td>Round-trip efficiency</td>
<td>90%</td>
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<tr>
<td>Hourly self-discharge rate (%)</td>
<td>0</td>
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**Other key inputs**
- Generator capital and operating costs
- Transmission capital costs, losses
- Weighted average cost of capital
- Fuel prices
- Value of lost load
- Operating reserve requirements

### Grid dispatch
- Energy + operating reserves
- Linearized unit commitment
- 21 "representative" weeks of operations at an hourly resolution

### Outputs

#### Storage outputs
- Installed energy capacity, power capacity by zone
- Hourly operating patterns
- Contributions to operating reserves

#### Other technology outputs
- Installed generation and transmission capacity by zone
- Hourly zonal power flows
- Hourly generation + storage mix
- Hourly operating reserve procurements

#### System outputs
- VRE curtailment
- CO₂ emissions
- Annualized capital investment
- Annual operating costs

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Impact of various system and technology drivers on storage adoption in deep decarbonization scenarios for 2050

<table>
<thead>
<tr>
<th>Key drivers considered:</th>
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<tbody>
<tr>
<td>- Availability of existing hydro &amp; low-carbon thermal generation (new nuclear, new gas+CCS)</td>
</tr>
<tr>
<td>- Model always could build new pumped storage, but always too expensive</td>
</tr>
<tr>
<td>- Inter-annual variability in load, renewables profiles (not shown)</td>
</tr>
<tr>
<td>- Flexibility of electric vehicle charging, other loads (not shown)</td>
</tr>
</tbody>
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<table>
<thead>
<tr>
<th>2017</th>
<th>2050 (greenfield + existing hydro)</th>
</tr>
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<tbody>
<tr>
<td>Peak load: 56 GW</td>
<td>Peak load: 74 GW</td>
</tr>
<tr>
<td>Annual demand: 275 TWh</td>
<td>Annual demand: 381 TWh</td>
</tr>
<tr>
<td>Emissions intensity: 247 gCO₂/kWh</td>
<td>Emissions intensity: 0-100 gCO₂/kWh</td>
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NY/NE Example Illustrates (Probably) General Patterns

- Tightening carbon constraints all the way to zero (EI0) raises optimal capacity, storage, and costs – but not dramatically.

- With nuclear an option & existing hydro available, it is never optimal to build more than 7 hours of Li-ion storage; better to build lots of wind & solar, curtail often.

- Without nuclear, hydro (& demand response), capacity, cost, & curtailment increase, but optimal average storage duration rises to only 10 hours.

- In a pure VER+storage system, **SRMC seems very low most of the time, but occasionally very high**, 87% & 2.3% of hours in one EI0 run.

- New national analysis of VER+storage (not shown): high-capacity long-distance transmission can drastically cut costs, large regional differences in optimal storage.
2050 greenfield scenario – unconstrained (no policy) emissions scenario vs. scenarios of decreasing emissions intensity requirements, differences not drastic

Emissions intensity of no policy scenario = 134 gCO2/kWh

CCGT with CCS ineligible for 0gCO2/kWh case due to 90% CO2 capture at power plant
System outcomes without CO2 emissions cap = 133 gCO2/kWh and 44% VRE penetration
2050 greenfield scenario - storage capacities grow with depth of decarbonization, so does role of new nuclear; < 7 hours storage duration for the modeled representative weeks

- Installed capacity
- Annual generation
- Capacity-weighted storage energy to power ratios

Storage power rating ~ 5-33% of peak demand
2050 Greenfield Scenario: Without low/no-carbon dispatchable resources (hydro, nuclear, CCGT-CCS), more & longer duration storage, higher average system cost of electricity

Capacity trends

System avg. cost of electricity

EI0 Storage impacts from nuclear, CCS and hydro availability

<table>
<thead>
<tr>
<th></th>
<th>Base case</th>
<th>No nuclear, CCS or hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>VRE curtailment</td>
<td>5</td>
<td>22</td>
</tr>
<tr>
<td>Energy to Power ratio (hours)</td>
<td>6</td>
<td>10</td>
</tr>
<tr>
<td>Storage % of total generation</td>
<td>6%</td>
<td>11%</td>
</tr>
<tr>
<td>Storage cycles¹</td>
<td>140</td>
<td>85</td>
</tr>
</tbody>
</table>

1. Storage cycles = annual energy throughput (MWh) / installed storage capacity (MWh)
2050 Greenfield Scenario: Without dispatchable low/no carbon sources, SRMC is generally very low but sometimes very high – 87% and 2.3% of hours in one EI0 run.
Basic Elements of 100% VER+Storage Systems

• **Instantaneous** capacity = max MW from VER + Max MW from storage
  – Varies stochastically with weather & charge history: *usual capacity market designs make no sense*
  – **Instantaneous** reserves = instantaneous capacity – instantaneous demand
  – System stress – low or negative reserves – can be triggered on the supply side (suddenly low wind) as well as the demand side (high AC demand), or on both sides (cold, cloudy winter day)

• **Instantaneous** sales to/from storage limited by MW capacity, state of charge
  – Net demand = final demand + power **to** storage (which increases future capacity)
  – Net supply = max VER output + power **from** storage (which reduces future capacity)
  – Instantaneously optimal decisions depend on the relation between the energy price and the shadow value of stored energy, which depends on future supply & demand, and on variable costs of storage
Very Low Stress Operation, MC = 0

SRMC, $/MW

final demand

Max VER Output

power to storage = Max Charge

Curtailment

MW
Low Stress Operation, $MC = \mu\text{(charge)}$

SRMC, 
$/MW$

final demand

$\mu\text{(charge)}$

Max VER Output

power to storage, < Max Charge

MW
High Stress Operation, $MC = \mu(\text{discharge})$

SRMC, 
$/\text{MW}$

$\mu(\text{discharge})$

Max VER Output

Final Demand

power \textit{from} storage
$< \text{Max Discharge}$
Very High Stress Operation, MC = VLL

SRMC, $/MW

VoLL

Max VER Output

Lost Load

Final Demand

power from storage = Max Discharge
Adding an Operating Reserve Demand Curve

• For efficiency, **marginal** retail energy price should equal SRMC + incremental losses
  – Tiny most of the time, *as in telecom*; efficiency cost of ATC pricing rises with ATC-SRMC gap
  – Efficient pricing will encourage electrification, discourage inefficient self-supply
  – Even with price-responsive demand, bang-bang pricing would not send *timely* signals of stress

• With a competitive wholesale market, wholesale energy price = SRMC
  – If $P_{\text{MAX}} < \text{VLL}$, generation and storage would face a serious *missing money* problem
  – Bang-bang energy pricing would not send *timely* signals to generators or storage providers

• Adding an *operating reserve demand curve* (ORDC), as in Texas, could help
  – If *instantaneous* reserves are low, the near-term probability of an involuntary outage is non-negligible
  – Increasing that probability is a social marginal cost and should be *added* to the marginal retail energy price and, with a wholesale market, to the price there – defines SRMC*
  – Would signal stress before outages, mitigate (but not solve?) the *missing money* problem
  – For this to work, system operator would need to know *instantaneous* reserves (including BTM assets?)
Very High Stress Equilibrium, $P = P_{\text{MAX}}$

- **Max VER Output**
- **Lost Load**
- **Final Demand**

- $MC, \$/\text{MW}$
- $\text{VoLL}$
- $P_{\text{MAX}}$
- $\mu(\text{discharge})$

- **SRMC+ORDC**
  - $= SRMC^*$

- Power from storage
  - $= \text{Max Discharge}$
Moving **Toward** Efficient Regulation of High-VER Systems

- States need to reduce distortions to incentives for investment in expensive, non-dispatchable BTM solar & storage: net metering, demand charges, constant rates…

- At retail, states need to increase SR fixed charges & reduce volumetric charges, toward SRMC*
  - Differences in fixed charges must be viewed as fair; use taxes (e.g. ITC) for some capacity costs?
  - Requires a shift in focus from pricing energy to pricing capacity (as was done in telecom)
  - Perhaps charge $X per kw of max instantaneous demand, chosen annually, plus $Y for “excess” usage – or shut off system when demand exceeds max (as in Spain & France)

- With or without markets, states must move away from using per-kwh retail rates to finance per-MWh subsidies & per-MWh PPA contracts for generators – a la RPS regimes
  - With carbon taxes, no need to distort retail rates to decarbonize
  - Any needed subsidies (ex ORDC) should be paid as SR fixed payments, not per-MWh
  - Perhaps fixed payments (or revenue requirements) for (negotiated?) minimum annual generation, no $ for excess generation, fines for significant shortfalls (as in Hawaii)?

- Federal policy must reduce NIMBY, rent-seeking obstacles to long-distance transmission
Some Remaining Questions, Puzzles, & Problems

• If BTM storage is important, can an ORDC regime work without central monitoring of charge & emergency control? Or will allowing aggregators to supply services be enough?

• How to manage systems in which, unlike today, SR fixed charges & payments dominate?
  • Easier without markets: utilities collect fixed charges, use them to cover (regulated) revenue requirements and (competitive) PPAs; transactions with other utilities are (lightly) regulated
  • With markets, what institutions (not today’s ISO/RTOs) will collect fixed charges from retailers & distribute them (by formula, by contract?) as SR fixed payments to wholesale G & T (& S?) suppliers?
  • If retail competition, who (supply or delivery) is obliged to levy fixed charges? Who sets requirements?

• Is central planning/IRP inevitable for utility-scale investment in high-VER systems?
  • With energy prices generally near zero & capped, & fixed costs high, generation investment will surely require capacity payments. Transmission does. What about storage?
  • Natural solution, as under integration: central planning of G & T (& S?) investment, plus, ideally, competition for capacity payments. New institutions seem necessary to do all this in market systems.
  • Is there a workable less centralized alternative?