The Shape of Things to Come: Net Demand

As wind and solar mature commercially they have novel effects on power system operations, planning, and finances. With Germany and California in the vanguard, policy solutions are emerging. But to best pursue a clean energy future we first must change the way we look at our power systems, starting with the daily load profile.

Bentham Paulos

The growth of wind and solar power are introducing a new element into grid operations, and changing the way grid operators look at the system. Indeed, they are changing the familiar daily shape of the demand profile.

In a traditional power system, grid operators track *gross demand*, the total amount of electricity demand that needs to be met in every second of every day. They then dispatch a fleet of power plants to meet that demand, following it as it rises and falls throughout the day. During emergencies they can curtail some customers, but by and large demand is considered a given, and power producers must respond to it.

But today's power system is increasingly

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different. Demand is no longer just a given, as information technologies and communications enable customers to respond to signals from grid operators and changes in prices. Distributed energy resources (DERs) can also supply ancillary services, such as ramping and voltage support.

The growth of wind and solar power is another significant change in power system operations. Because wind and solar are driven by the weather and the rotation of the Earth, they are not controlled by grid managers. Like demand, they are an "exogenous" variable, coming from an outside source.

Grid operators have begun to look at the system in a new way: instead of meeting gross demand, they are now meeting net demand, treating wind and solar production as a given, albeit an intermittent one, and subtracting it from the total electric demand.

You could say that they have discovered the grid operator's Serenity Prayer: "God, grant me the serenity to accept the things I cannot change, the courage to change the things I can, and the wisdom to know the difference."

Experience in Germany

This world view is beginning to become part of the new normal, as it transitions from academic venues to practitioners and policymakers. This is especially true in Germany and California, as both regions surpass 20 percent of annual electricity production from renewables.

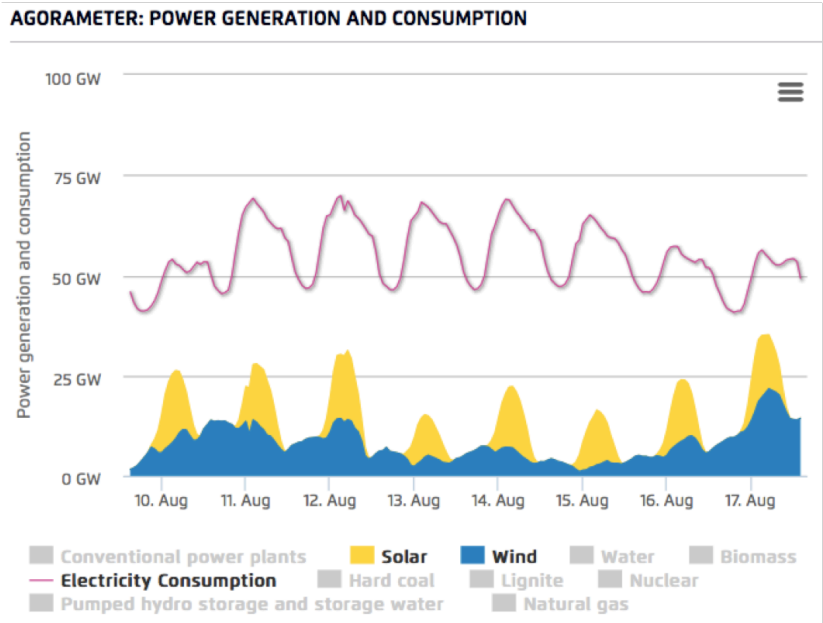
Because wind and solar are variable, a 20 percent average output can result in periods of very high renewables production, causing significant changes in the daily load profile of a utility system.

To illustrate this fact, we took a look at two representative weeks in 2014 from Germany and California.

Using data from Agora Energiewende's *Agorameter*, we subtracted out wind and solar to find the net demand in Germany for the week of August 10, 2014. The result shows big changes to the shape of the demand profiles, the size of the daily peak, and the minimum load.

The good weather that week resulted in renewables hitting 79 percent of demand on a

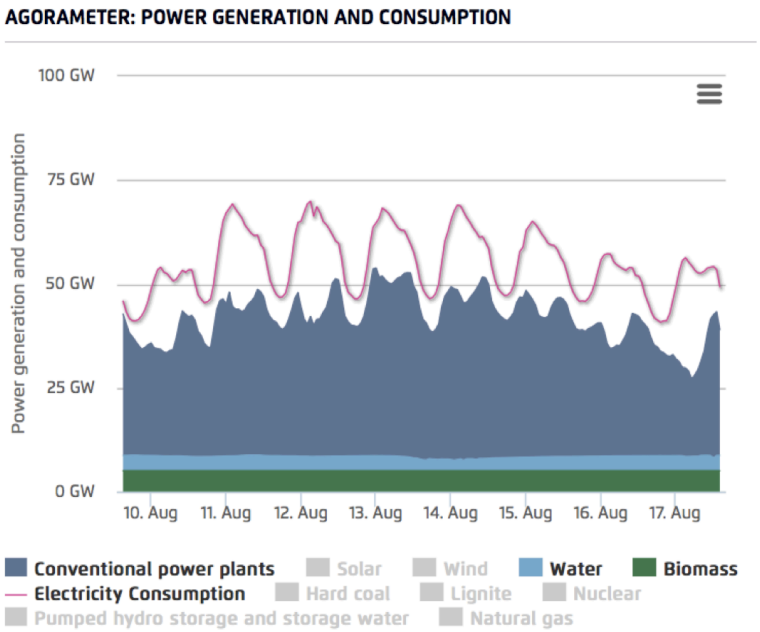
Figure 1: Gross demand and wind/solar production in Germany, week of August 10, 2014



sunny and breezy Sunday afternoon. In **Figure 1** on page 2 the top red line is gross demand, while wind and solar are depicted in blue.

Figure 2 shows the net demand, which is gross minus wind and solar, depicted in dark blue. Wind and solar cut peak demand by about 10 GW, around 15 percent, and cut the daily minimum by almost 15 GW.

Figure 2: Net demand in Germany, week of August 10, 2014



These changes have big implications for both operational and financial aspects of the German power system.

First, there is a much lower need for total dispatchable capacity at times. In summer, solar power is well-correlated with peak demand, reliably cutting off peaks almost every day. This is not true in the winter, when Germany's high latitude results in short days and very poor solar output. Because Germany is a winter-peaking system solar is given no capacity value. However, wind tends to be stronger in winter, driven by coastal breezes off the North Sea. On January 11, 2015, for example wind hit almost 60 percent of national demand.

Second, the net demand shape has big financial impacts. In Germany's "energy-only" power market, most spot market revenues for power generator are earned during periods of peak demand, which is also when prices rise. Losing these lucrative peak periods to solar means a significant loss of revenues for conventional generators.

Wind has its own less predictable impacts on market prices. When wind hit 60 percent of demand recently, spot prices dropped to -25 Euros per MWh for an hour, and hovered between zero and 10 Euros for most of two days.

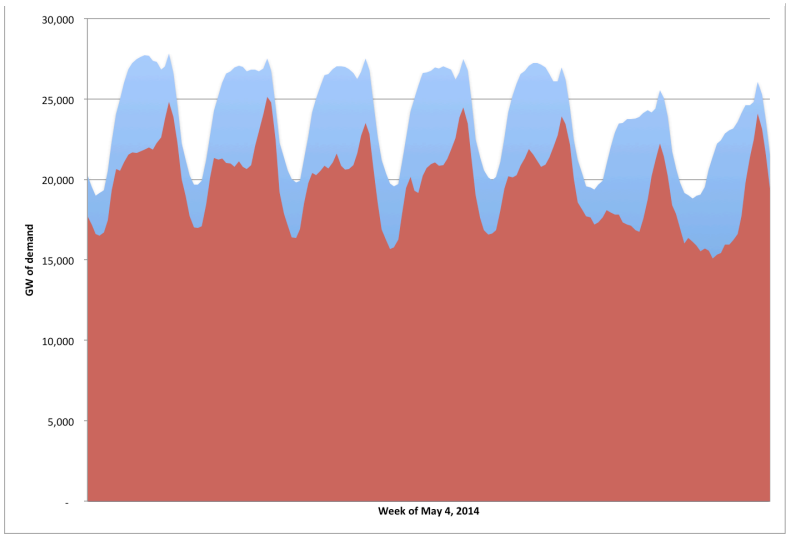
Because wind and solar are paid largely through feed-in tariffs and marketing incentives, they are insulated from the price impacts they cause on the spot market.

Experience in California

California is already seeing similar impacts from wind and solar.

The California ISO now reports net demand curves in real time on their web site and mobile app.

Figure3: California gross and net demand, week of May 4, 2014



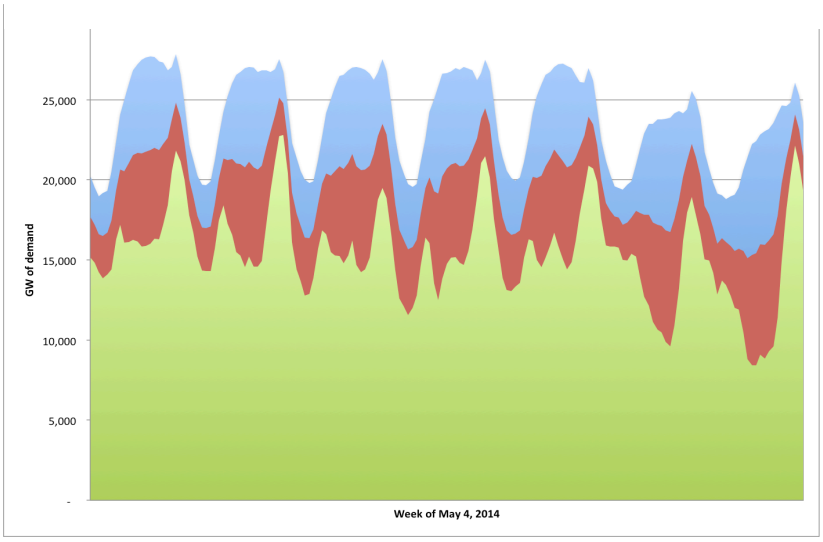
Looking at another pleasant week in May 2014, where wind and solar amounted to 18 percent of total demand for the week, we found similar effects. Like in Germany, wind and solar hit 31 percent of demand on a pleasant Sunday afternoon.

Figure 3 shows gross demand in blue and net demand in red for the week of May 4. Compared to gross demand, the net profile has a slightly lower peak and a much lower minimum demand. But the biggest difference is in the shape of the load profile. While the sun starts to go down late in day, the air conditioning load persists into early evening, starting to create the famous "duck curve" that the California ISO has identified.

While 18 percent renewable energy is notable, California expects much higher levels in its future. The law requires 33 percent renewables by 2020, and in January Gov. Jerry Brown called for extending the target to 50 percent by 2030. Thanks to AB327, the California PUC has the authority to set that target, even without further legislative action. While the RPS covers all renewables, including California's plentiful geothermal, small hydro, and biomass, most growth in renewables is expected to come from wind and solar.

For a quick analysis of the future, we simply doubled wind and solar for the same week, to 36 percent of total. In **Figure 4** the green area is the net demand in the doubled wind and solar scenario. This change continued to lower the peak and caused a huge drop in minimum demand, down to only 8 GW.

Figure 4: ***California demand profile with doubled wind and solar, based on week of May 4, 2014***



But a late afternoon peak persists, causing a vastly different load shape. In the world of gross demand, the peak occurred all day long; but large amounts of solar push the peak to a period from about 4:00 to 7:00 pm.

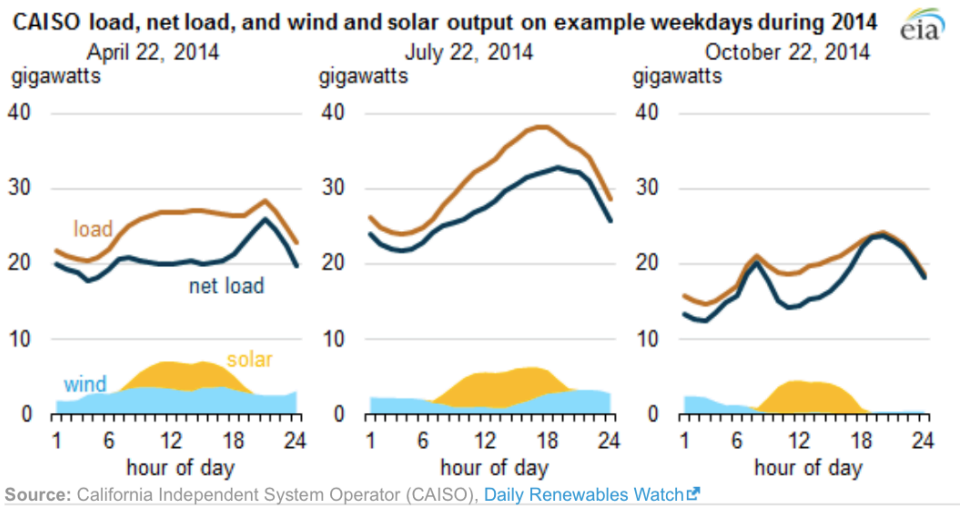


Figure 5: EIA analysis of California net load

These shorter duration peaks allow a larger variety of tools to be deployed to meet the demand, like demand response, thermal storage, and west-facing solar panels. Electric vehicles can provide grid services and raise up the daily minimum through on-peak charging. Shorter peaks make battery storage more viable, given their shorter discharge time.

The US Energy Information Administration recently reported on net demand in California. It pointed out that rapid growth in the past year has resulted in utility-scale solar providing more than 10 percent of peak demand. This 5 GW of "big solar" does not include distributed behind-the-meter solar, which the state estimates at 2328 MW currently, and growing rapidly.

It points out that the load profile impacts vary by season, as shown in **Figure 5**, above.

As California and Germany grow they will start to look like Denmark's much smaller system has looked for some time. The Danish grid operator, Energinet.dk, graphed out the gross and "residual" demand in the winter of 2007, as shown in **Figure 6**, on page 6. This two-month period saw a large amount of wind production, along with combined heat and power (CHP) production for district heating systems. The power output of these systems is considered must-take power, since it is a byproduct of the heating systems.

Denmark's primary strategy in handling its system is to trade power in the Nordic Pool, especially Norway's large hydroelectric system.

This radically different net demand profile is an indicator of where California, Germany, and other regions are headed.

Lessons learned

We can draw lessons from experience in these regions.

First, electric systems will need much more flexibility. To avoid conflict during periods of large wind and solar output, other resources will have to be able to get out of the way, by turning down or off. If plants lack sufficient "turndown" ability the system will see "over-generation"—an unsustainable condition.

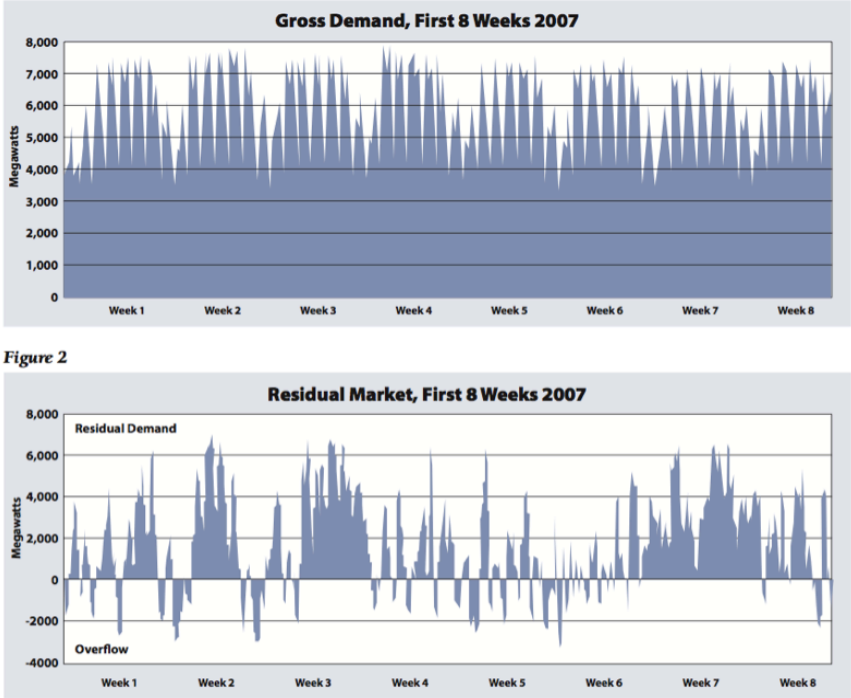


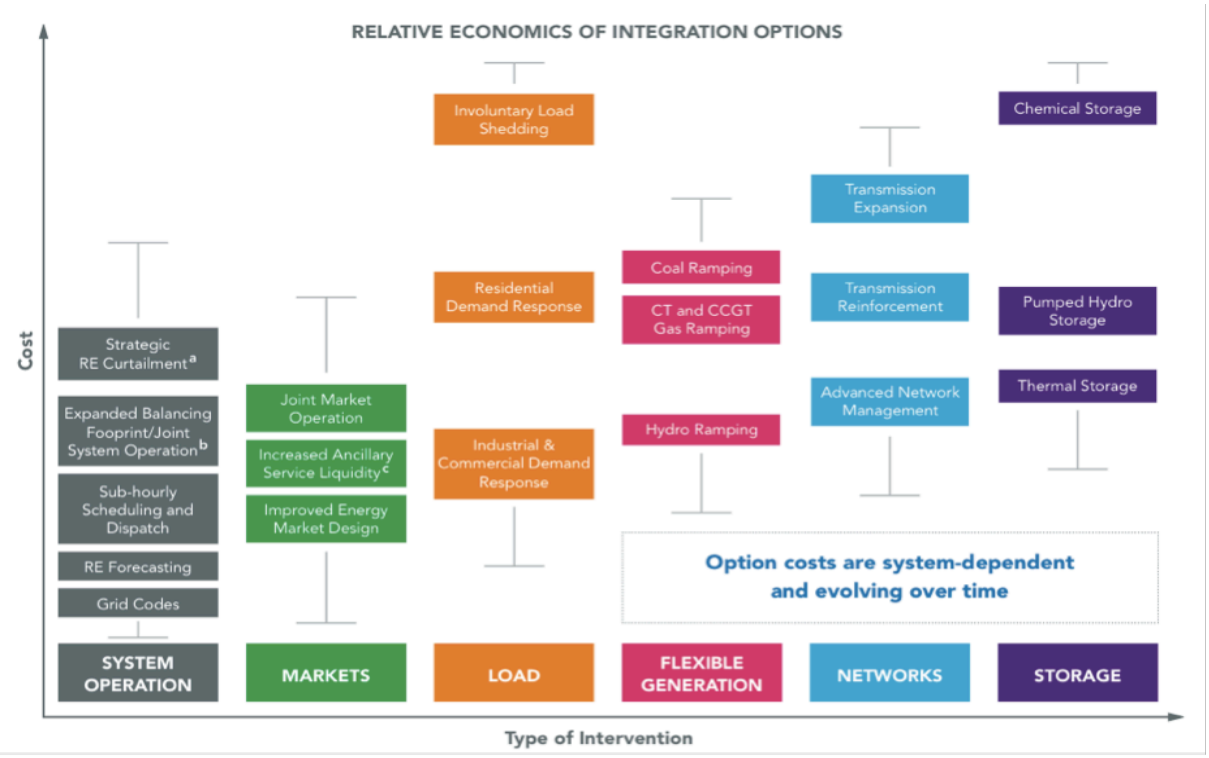
Figure 6: Denmark's gross and net demand, winter 2007

One step will be to increase the flexibility of inflexible "baseload" power plants, like large coal and nuclear, or retire them. Otherwise it will be necessary to curtail wind and solar generators, which, as consulting firm E3 showed in an analysis for California utilities, is also the most expensive solution, wasting millions of dollars of emission-free electricity. In markets that reveal prices, overgeneration can cause prices to go negative. This is good for consumers but can be hard on generators, making it hard to earn a profit.

A second lesson is that a high renewables future will have "less traffic in the mountains." There will be less demand for energy from sources other than wind and solar in the mountainous area between peak and baseload, and thus less revenues from energy sales for dispatchable generators. At the same time, it will create more need for ancillary services, like ramping and capacity, which dispatchable generators can provide. A change in market policies will provide more revenues for flexibility services.

A third lesson, as mentioned above, is that the thin afternoon peaks in California will make a host of other tools viable for serving peak needs, like demand response and storage. All of these will need correct price signals to be deployed, such as time-of-use rates and dynamic pricing.

Figure 7: The costs of integration options.



In sum, there are many integration options, with varying levels of cost effectiveness. An analysis by the 21st Century Power Partnership developed a conceptual supply curve of integration options (**Figure 7**). It identifies "system operations" and "markets" as the first steps. The least expensive options are primarily regulatory changes, like consolidated balancing areas and sub-hourly scheduling. Technological options, like flexible power plants and battery storage, tend to be more expensive.

EIA points out that California policymakers have already begun to adopt policies that encourage greater flexibility.

- **Flexibility products:** The California Public Utilities Commission (CPUC) has adopted a flexible capacity framework to start in 2015, requiring utilities to procure a certain level of flexible capacity. The CAISO started a flexible ramping constraint in 2011 and is further considering introducing upward and downward ramping products into its real-time and day-ahead markets.

- **Storage:** A 2010 legislative mandate requires that the state's three investor-owned utilities procure 1.325 GW of energy storage by 2020, starting in 2015. Southern California Edison already announced plans to buy 260 MW of storage in its "local capacity requirements" solicitation to replace resources lost to new water-use regulations and the retirement of the San Onofre nuclear plant.

- **Sub-hourly scheduling:** In May 2014, CAISO started scheduling resources at 15-minute intervals, to comply with FERC Order No. 764.

- **Energy imbalance market:** In November, CAISO and PacifiCorp formally launched an energy imbalance market (EIM) that merges the balancing function of both regions, thereby reducing costs and variability. It will be expanded to include NV Energy in October 2015.

- **Time-of-use pricing:** AB327 gives the CPUC authority to implement default time-of-use rates for residential customers starting in 2018. A docket is currently underway.

- **Demand response:** DR has been slow to take off in California, but legislation from September 2014 urges the CPUC to get the job done, such as by including demand response as a resource adequacy requirement.

Conclusion

At modest levels, wind and solar are simply absorbed in the variability of the power system. But as they mature commercially, and grow to more substantial levels, they are having novel effects on power system operations, planning, and finances. With Germany and California leading the way, policy solutions are beginning to emerge.

But to pursue a vision of a clean energy future we first must change the way we look at our power systems, starting with the daily load profile. □