Understanding Challenges with Intermittent Renewable Electricity Expansion

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At a Glance

Collaborating with analysts at NRG Energy, the largest competitive power producer in the US, the Energy Systems Analysis Group (ESAG) launched a new initiative in 2016 to model the prospective evolution of high penetrations of intermittent renewable electricity supplies (iRES – mainly wind and solar photovoltaic) on US grids. Major challenges must be addressed to reach high iRES penetrations cost-effectively. The research seeks to understand and articulate the cost and carbon implications to mid-century of deployment of various grid technologies interacting with alternative electricity and carbon market redesigns.

Research Highlight

Incentives from governments around the world have led to rapid growth in iRES while R&D and experience have led to dramatic reductions in their capital costs—trends that are expected to continue. There are at least three major challenges to be understood and addressed to realize high iRES penetrations.

One major challenge is providing electric balancing capacity in the form of backup or storage. This challenge is well-addressed today by natural gas-fired combustion turbine (CT) and combined cycle (GTCC) backup units, together with iRES curtailment whenever iRES exceed demand. However, as iRES grid penetration increases, iRES generation costs will rise despite falling capital costs, because such curtailments will increase rapidly. California might be considered a window to the future of iRES. Under the state's new 50% Renewable Portfolio Standard (RPS) mandate, iRES is expected to reach 35% of total generation by 2030[1]. Figure 3.2.1. illustrates the iRES over-generation problem for California, where future iRES is expected to be dominated by utility-scale solar photovoltaic electricity.

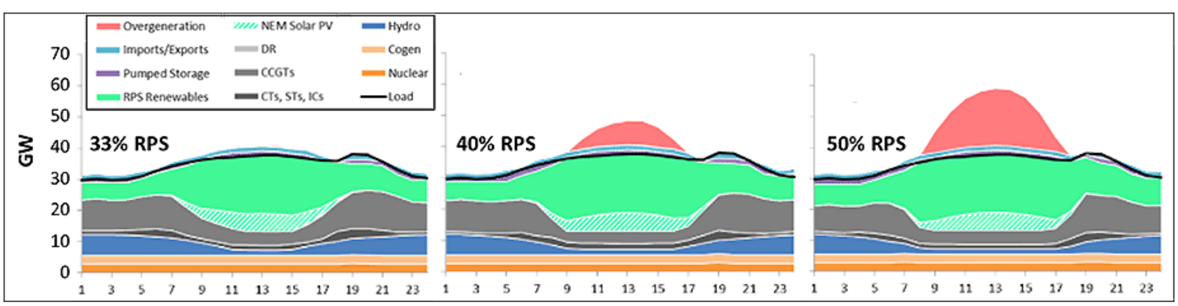

Figure 3.2.1. Modeled base-case electricity generation for a day in April 2030 for the California independent system operator (CAISO) grid with different RPS requirements and absent new bulk electricity storage[1]. To satisfy the 50% RPS, about 20 GW of PV generation (the over-generation rate, in red) would need to be curtailed at mid-day.

High iRES grids dominated by either wind or solar are likely to require high iRES curtailment rates, although for wind, the iRES supply pattern will be less predictable, over-generation will take place at different times of day, and required ramping rates for balancing capacity will typically be faster. Figure 3.2.2. illustrates these features for Texas, which currently has by far the largest wind generating capacity of any US state (18.5 GW): wind power output *(a)* is typically strongest at night, *(b)* drops sharply in the morning as load is rising, *(c)* picks up again in the evening as load begins to drop, and *(d)* varies significantly day by day (also season by season).

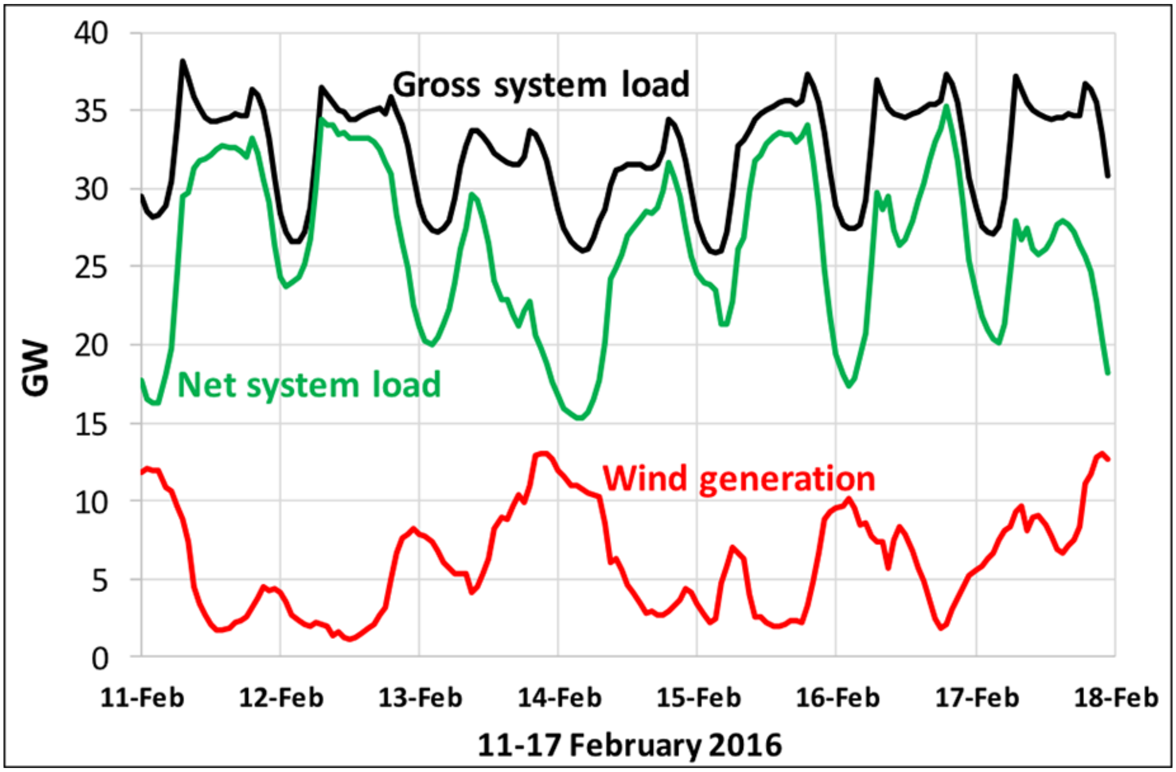

Figure 3.2.2. Seven days of wind power output and electric load for the grid operated by the Electric Reliability Council of Texas (ERCOT)[2]. Net system load is calculated as gross load minus wind generation.

In both solar-dominated and wind-dominated iRES cases, the mismatch between iRES and load means that the system operator needs to curtail over-generated iRES at times and to rapidly adjust backup supplies at other times in order to reliably satisfy electricity demand. Grids with high iRES made up of a more balanced mix of solar and wind are likely to have lower curtailment rates, partly because wind and sun may be available at different times.

Curtailments of iRES can also be mitigated by storing over-generated electricity. Bulk electricity storage via batteries over periods longer than a couple of hours is expensive[3], and pumped hydro storage (PHS) is geographically constrained. However, natural gas-fired compressed air energy storage (CAES) is likely to be less costly than PHS and potentially deployable throughout most of the US[4]. CAES is commercially ready for storage in salt caverns (deployable in wind-rich regions such as Texas and possibly also the Rocky Mountain and northern Great Plains regions[5]) and might be cost-competitive with new CT backup capacity[6]. CAES could be much more widely available via storage in porous media (expected to be less costly than salt caverns[4]) and mined hard rock—options that have not yet been demonstrated.

A second major challenge to high iRES penetrations is the reduction in carbon dioxide (CO_2) emissions from balancing capacity that likely will be required to meet long-term carbon-mitigation goals. This can be accomplished via some mix of electricity storage (including natural gas CAES) and Carbon Capture and Storage (CCS). The latter is challenging because of high costs for CCS-integrated balancing capacity units that have to operate at low capacity factors, as will be the case with high iRES grid penetrations. Plausible strategies for addressing this challenge effectively have been proposed[7].

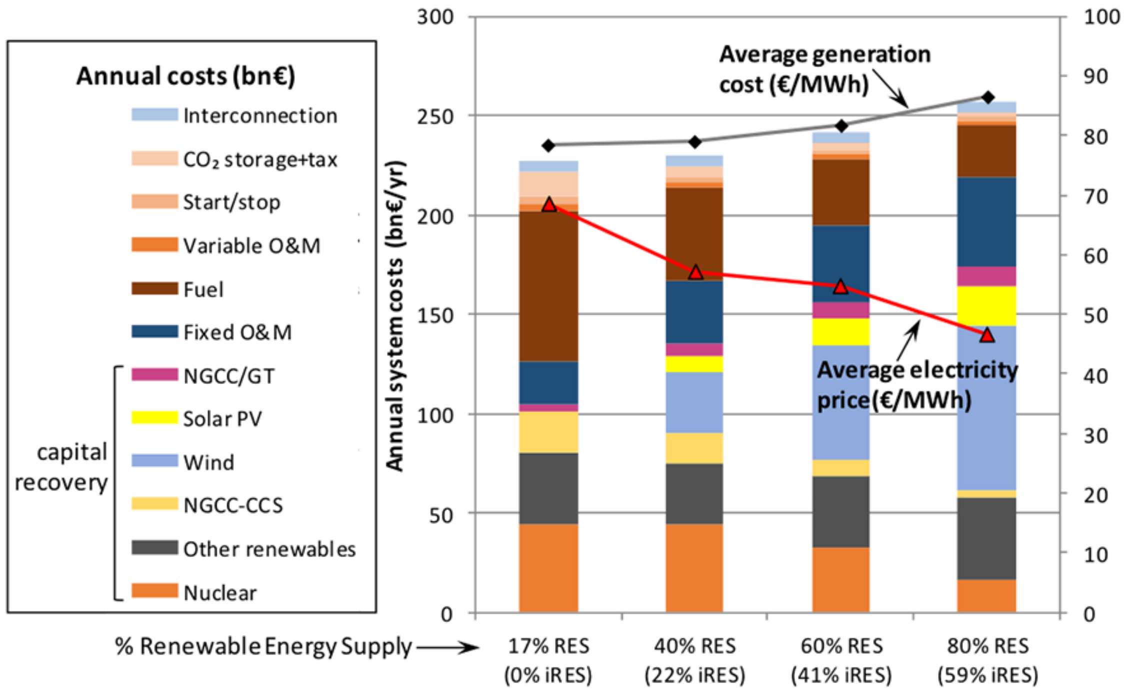

Figure 3.2.3. Alternative low-carbon electricity scenarios for Western Europe in 2050[8] illustrating the problem with short-run marginal cost pricing of wholesale electricity as penetrations of iRES increase. The cost of electricity supply (black line, right axis) is higher than the market price paid for electricity based on marginal-cost pricing (red line), and the gap grows with level of iRES penetration. Each bar shows the lowest annual system cost in 2050 (left axis) for the assumed iRES penetration and short-run marginal-cost-based dispatching. Each scenario meets exogenous system reliability and CO_2 emissions constraints (96% lower than in 1990). The CO_2 emission price in the scenario with 0% iRES is 165 €/t, the price needed to induce the needed investments in non-iRES low-carbon options. In the other scenarios, a 70 €/t price is applied, the value that induces investment in a natural gas combined cycle with CCS.

A third major challenge is that increasing penetrations of iRES threaten the effective functioning of wholesale electricity markets, in which the price paid to all generators is set by the operating cost of the marginal unit. Because the operating cost of iRES is close to zero, large iRES penetrations significantly depress the prices paid to *all* generators, even those that play critical balancing roles and others with desirable features such as low carbon emissions. Continuing traditional short-run marginal cost-based pricing of wholesale electricity in the face of continuing iRES penetrations threatens new investments of any kind needed to maintain a reliable grid, including investments needed to realize deep decarbonization goals. Brouwer, *et al.* [8] demonstrate how traditional marginal-cost electricity pricing is increasingly untenable as iRES penetrations grow (Fig. 3.2.3). New policies that adequately reward generators for critical attributes like low-carbon emissions and balancing capabilities are needed to resolve this dilemma.

ESAG continues to build a relationship with analysts at NRG Energy and is working with them to conceptualize a modeling framework for analyzing the impacts that different grid technologies and electricity-market redesigns would have on achieving iRES penetration and carbon-mitigation goals. Models used by others can be loosely classified as capacity expansion, which typically examine impacts of alternative policies on mid-to-long term generation mixes, but without considering economic dispatch competition and associated wholesale-electricity market structures[9]; or unit commitment-dispatch which are typically designed to simulate day-by-day, hour-by-hour economic dispatching for a geographically-specified power grid[10]. Both types of models require large numbers of inputs and considerable computation times, making them unwieldy for exploring multiple scenarios. ESAG seeks to develop a modeling framework that combines essential features of both model types, but maintains sufficient simplicity and nimbleness that alternative technology and policy scenarios can be studied with manageable computation times.

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[3] Lazard, 2015. Lazard's Levelized Cost of Storage Analysis – Version 1.0.

[4] Electric Power Research Institute, 2008. Compressed Energy Storage Scoping Study for California, prepared for the California Energy Commission's Public Interest Energy Program, CEC-500-2008-069.

[5] The only commercial CAES technology involves caverns solution-mined in salt domes, which are available in the Gulf Coast region of Texas. Such caverns could also be created in the bedded salt formations that are available in the Rocky Mountain and Northern Great Plains regions, although creating salt caverns in bedded salt is more challenging. (S. Succar and R.H. Williams, 2008. Compressed Air Energy Storage: Theory, Operation and Applications, a report of the Energy Systems Analysis Group prepared for BP, Princeton Environmental Institute, Princeton University.)

[6] The specific capital cost ($/kWe) for a natural gas-fired salt-cavern CAES unit with 10 hours of storage is likely to be no higher than for a new CT, and the natural gas required per kWh is ~2/5 of that required for the CT unit[4]. The latter benefit will be offset to some degree by the cost paid for the IRE that will be stored.

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