The Governor's Conference on Local Renewable Energy Resources

California's Path To Local Renewables

Reliability and Interconnection Panel
Discussion Paper

SUMMARY

Fundamentally, the successful integration of local variable energy resources ("VERs") which are by definition intermittent in nature, involves the consideration of three primary issues: (1) the need to maintain reliability (2) the need to contain customer costs, and (3) the need to provide regulatory and financial security for investors and technology developers. These three issues can form the basic structures for any localized energy goal.

One critical consideration is to avoid defining VERs too narrowly. A too-narrow definition of VERs will overly constrain operational flexibility making it more difficult to maintain reliability. A broader definition of VERs could consider demand side management (DSM, or actions that influence the quantity or patterns of use of energy consumed by end users), combined heat and power resources (CHP), behind-the-meter solar or community wind facilities, small scale renewables, small hydro and small biogas/biomass generators, storage and smart grid upgrades on the distribution system. Developing a broad portfolio of resources has been demonstrated to improve short and long term reliability concerns.

In addition, we face the legacy of an existing power grid that was designed and built around large centralized power plants, generating cheap power and sending the power out in one direction over the transmission wires. Current best practices in Germany and Spain address their sizable growth in distributed renewable power generation successfully, but in part due to a grid that includes better reporting of load and generation shifts, and protection against intense local variation. As one senior German energy official recently told a member of the Governor's staff, "What you call the smart grid, we call the grid."

Other areas that worry grid operators about overall system operability include" steady state voltage regulation and transient over-voltages in pockets of the low-voltage distribution where there is high penetration of variable and intermittent renewable generation, but little load: power quality concerns about harmonics or power line distortion due to (1) electronic loads or inverter based generation that can interfere with utility protection and damage equipment and (2) high/low transient voltages that can interfere with and/or interrupt sensitive equipment at customer facilities.

Given the as yet unknown costs of grid improvements in California associated with these operations concerns, utilities and regulators are worried about rate impacts. Utilities and government regulators will take the blame for power outages and high costs of electricity, not owner and operators of renewable power generating facilities or advocates.

ISSUES AND CHALLENGES

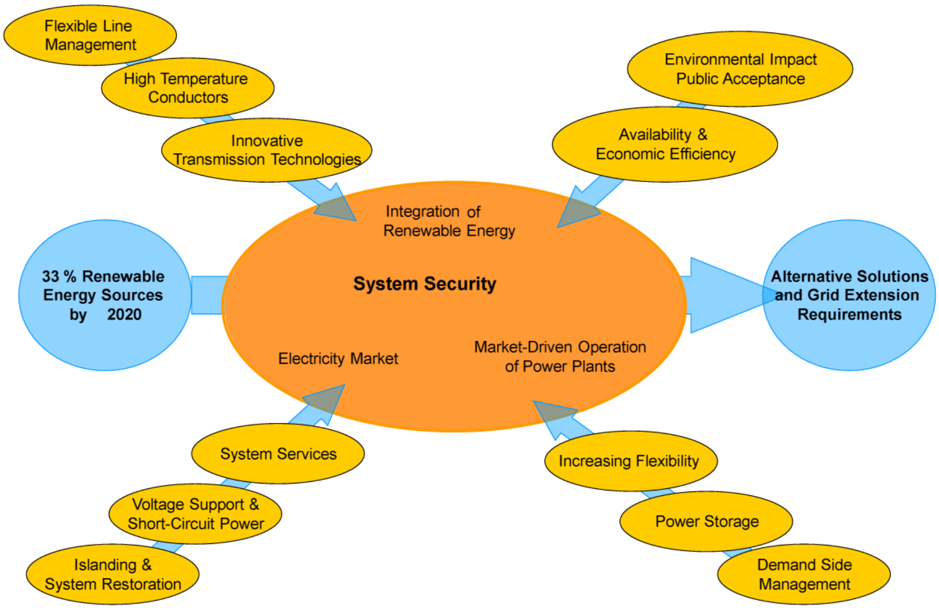
The impact of deploying 12,000 MW of small (<20MW) Variable Energy Resources ("VER"s) on the CA distribution grid.

- Is this technically feasible and practical?
- Can this be done without adverse effects on costs, system stability, reliability?
- Lessons learnt from similar programs? Do we need a comprehensive regulatory initiative to achieve the goals and beyond?
- Are existing regulatory compliance requirements adequate to support the deployment of 12,000MW of VER by 2020?
- Specifically is there a need to streamline the permitting and compliance processes' in the short term.
- How to best attract private sector investment to support deployment of 12,000 MW of VER?

BACKGROUND

There is strong evidence that we can accommodate large amounts of renewable power in our electrical system. A wealth of technical, financial and regulatory information exists from previous and existing programs both here in California and overseas, particularly in member countries of the EU, which have introduced binding regulations and continue to invest heavily in new technologies to reduce GHG emissions and energy consumption. The German power industry have conducted a comprehensive investigation[1] into suitable system solutions to fully integrate 39% renewable energy in the power supply into the German power grid while guaranteeing the security of supply and taking the effects of the liberalised European energy market into account.

[1] Dena Grid Study II



Source: Dena Grid Study II

It is interesting to note that the following assumptions were made for 2020 in the dena study:

Phase-out of nuclear energy (per Nuclear Energy Phase-Out Act [Atomausstiegsgesetz 2000])4

- 39% integration of renewable energy (RE) sources in accordance with the Renewable Energy Sources Act by 2020, and 100% by 2050.
- 25% combined heat and power generation in electricity generation by 2020
- Market-driven use of power plant and storage facilities (in conjunction with cost-optimised operation) and development of the fleet of power plants and storage facilities in the model calculation used according to market driven economics - (maintaining FIT's, and other economic incentives).
- Limitation of the European electricity market solely via the capacity of the cross border transmission lines.

Despite its geographic location, Germany has already achieved one of the highest levels of RE in the world (40% RE is reached at times of strong wind and off-peak). In the long term, 2050 and beyond Germany is planning for 100% RE.

Similar studies have been carried out in the UK[2]. The UK study reviewed over 200 reports and studies on the impacts of variability and intermittency introduced by RE

[2] The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network. A report of the Technology and Policy Assessment Function of the UK Energy

resources on the reliability of the electricity supply system. The main conclusions from this study were:

- None of the 200+ studies reviewed suggest that introducing significant levels of intermittent renewable energy generation on to the British electricity system must lead to reduced reliability of electricity supply.
- Many of the studies consider intermittent generation of up to 20% of electricity demand, some considerably more.
- It is clear that intermittent generation need not compromise electricity system reliability at any level of penetration foreseeable in Britain over the next 20 years, although it may increase costs.
- In the longer term much larger penetrations of RE may also be feasible given appropriate changes to electricity networks, but this report does not explore the evidence on this topic.
- The introduction of significant amounts of intermittent generation will affect the way the electricity system operates.

The UK studies conclude that there are two main categories of impact and associated cost at high levels of variable RE resources.

> *The first, so called **system balancing impacts**, relates to the relatively rapid short term adjustments needed to manage fluctuations over the time period from minutes to hours.*

> *The second is **'reliability impacts',** which relates to the extent that sufficient generation will be available to meet peak demands. No electricity system can be 100% reliable, since there will always be a small chance of major failures in power stations or transmission lines when demands are high. Intermittent generation introduces additional uncertainties, and the effect of these can be quantified.*

These two bodies (German and British) of significant study both conclude that storage and CHP will be important assets in any future power generation/supply system that has >20% embedded variable sources of power generation.

In addition, the 2011 IEA report "Harnessing Variable Renewables – A Guide To The Balancing Challenge" indicates that the technical potential for VER integration in the Western US (WestConnect) will be at least 45% on an energy basis in 2017[3] without significant changes in the generation mix, or new technologies such as energy

[3] While the required flexibility is in place from the standpoint of generator ramping capability and transmission infrastructure, successfully managing this level of penetration would require significantly improved balancing area cooperation and scheduling practices from the current status quo.

storage or widespread demand response. The same report summarizes the findings of numerous large-scale, recent studies that find modest balancing costs for VERs, ranging from $1 - $7 / MWh, to manage incremental variability in the power system[4]. The June 2011 "2010 Wind Technologies Market Report" published Lawrence Berkeley Laboratory summarizes similar data, and also shows that where subhourly (15 minute) scheduling is used, incremental balancing reserves required to manage wind generation are 10% or less of the incremental wind capacity, at penetrations exceeding 50% on a capacity basis[5].

Empirically and as a practical matter, power systems around the world are successfully accommodating variable generation at levels of penetration that were deemed to be impossible by many, even just a few years ago. Denmark currently generates 26% of its energy from wind. Portugal and Spain supply about 17% and 15% of energy from wind, respectively. The latter two countries are particularly relevant to California since they collectively represent a power system that is similar in size to California, but are weakly interconnected to the rest of Europe so cannot rely on the extensive hydroelectric resources leveraged by Northern European countries for balancing. Spain also boasts over 3.4 GW of photovoltaic generation, serving about 3% of its load.

As just another example of the recent evolution of thinking on this matter, PJM – the transmission system operator serving much of the Northeastern US – recently launched an integration study which includes a "pain point" case, where penetration in the study will be increased until operational "pains" become evident. Based on previous studies and experience, PJM expects that 30% of VER (wind and solar) on an energy basis will not reach this threshold, and the study will have to go beyond this level to reveal issues. It is worth pointing out that, in contrast to the study goals, PJM has a RPS-mandated 15.1% VER penetration by 2026 in its footprint <ref>.

Many problems we face today with implementation of RE and DVR systems are largely a legacy of an existing power grid that was designed and built around large power plants, generating cheap power and sending this power out in one direction over wires designed to accommodate an ever growing electricity demand. The power grid was built before silicon chips and the accompanying IT revolution and there is frighteningly little intelligence built into the existing grid. Unfortunately, the flow of electrons and power on the existing grid cannot be managed and controlled in the same way that photons and information are managed on the internet. The as-

[4] Generally assessed at a penetration of 20% of delivered annual energy, though the Western Wind and Solar Integration Study (WWSIS) found costs of less than $5 / MWh for a mix consisting of 30% wind and 5% solar (35% VER overall) and the Eastern Wind Integration and Transmission Study (EWITS) found similar costs for 30% wind penetration.
[5] Where hourly scheduling is used, this ranges up to 18%.

yet unknown costs of these improvements are likely to be a source of concern for utilities and grid managers.

The inherent variability and uncertainty of these resources often sparks concern that as penetration increases, power quality and power system stability could be compromised and / or integration costs will be unacceptably high. This concern also looms large for utilities, whether public or investor-owned, as under law and in the public's perception, they will bear responsibility for any power outages, not the owners and managers of renewable generation.

For PV generation, in many cases these perceptions are based on output data from single, typically fairly small systems under partly cloudy conditions. This data typically shows very large changes in output over short timeframes (80% per minute or more). Understandably, such data sparks concern over the ability to manage such large changes as PV system penetration increases.

However, a large and growing body of data demonstrates that the total variability is damped significantly as the output of multiple PV systems are aggregated, significantly mitigating concerns about this short-duration variability. This occurs not only over large geographic areas, but even over quite short distances, with significant reduction in variability occurring even within the footprint of a modestly sized PV system. Empirical experience, particularly from Germany, also suggests that short duration variability is not a significant barrier to integration of PV even at high penetrations onto the distribution system.

Longer duration variability – the overall changes in output within an hour – is also of concern, in particular from a systems operation perspective as fairly large amounts of conventional generation must be ramped relatively quickly in response. As this is driven primarily by the diurnal movement of the sun through the sky (rather than weather conditions), diversity has little effect. Conversely, this type of ramping is highly predictable. At 33% penetration in CAISO, regardless of scenario, current indications are that these ramps can be managed without significant issues.

Utilities, regulators and grid managers still remain concerned about the costs of improving our grid in order to reach the flexibility that European grids have built into their electrical system. . This includes the interconnection costs faced by LER developers as well as the transmission and distribution upgrade costs potentially borne by the utilities and their customers. If the amount of generation available at the distribution level exceeds the load demand of the immediate area, the excess generation would likely create a burden on the distribution system in the area, as well as the local transmission system. Problems associated with ensuring adequate capacity, proper equipment ratings, adequate protection, and voltage regulation would increase with increasing reverse and intermittent power flow. This may result in high interconnection costs to the generator, the utility and utility customers.

Ultimately, the cost containment challenge would lead to potential rate impacts. Depending on the disposition of the power (customer-side vs. on-grid), as well as the expected procurement approach for on-grid power (e.g., competitive solicitation), significant upward pressure on rates is possible. Significant upgrades to distribution systems to handle the two-way flow of power are expected to be required. Furthermore, adding significant amounts of LERs of variable or intermittent nature will increase the amount of integration needed to reliably operate the transmission and distribution systems.

An additional cost containment challenge relates to market operations. Significant increases in LERs will create a new challenge in market operations – not only will load or demand change without information to operators – but, now LER generation alsochanges without operator instructions (i.e., a lack of visibility and operational control over LER generation). The corresponding "integration services" needed to keep the grid reliable will create additional costs. Consistent with cost causation principles, it is suggested that the cost associated with these integration services should flow back to the LER generation. Proper cost causation (to both load and generation) should lower total integration costs and reduce operational burdens.

SOLUTIONS

Fundamentally, there are no technical roadblocks to achieving the goal of 12,000MW VER

- Evidence from similar initiatives overseas (EU in general, Germany specifically, etc.) suggests that a stable regulatory regime and long-term predictable financial environment are needed to attract the necessary private sector investment. Early power industry concerns regarding variability and reliability issues have proven unfounded for <40% penetration of RE on the grid.
- A portfolio of different VER technologies, including storage (some feel that storage may be very important as an option to integration issues, but also application specific) and other fast acting VER's, including fuel cells, CHP, Waste-Heat-to Power (WH2P), smart grid, etc. can make substantial contributions to both system stability, reserves and GHG reductions. In addition, maintain a portfolio that is diverse across geography helps to reduce risk to system stability.
- Comprehensive regulations help streamline the roll-out of VER's. Simple regulations such as Feed-in-Tariffs or targeted incentive programs will help encourage long term investment in VER's. Encourage diversity in

applications and ownership models – allow markets and technologies to compete for these services.

- Based on inverter testing, modeling and system modeling done by SCE over the last year and a half, several inverter functions have been identified that can help with high penetration situations. The following are examples of inverter features that can support system integration: the ability to regulate voltage and reactive power (voltage/VAR control), fast overvoltage protection when islanded with little load, limited fault current contribution, potential for low voltage ride through, low harmonic distortion including filtering of pulse width modulation frequencies, the ability to remotely curtail power output during system emergencies and the ability to communicate to/from utilities in a standardized manner

- Changes to power system infrastructure and regulations must be future-proofed and help pave the way for larger percentages of RE integration in the power system. Better reporting on both demand and distributed power generation will become critical for grid managers. But, while high resolution real time monitoring data and control over every PV system may sound preferable, California' smart grid infrastructure is not yet in place, and improved modelling may help to bridge in the interim.

- Learn by doing (avoid analysis paralysis) – accelerate progress in existing rulemakings and encourage field deployments as soon as possible. In Germany, where every PV interconnection is studied, simplified methods are often used, and the requirement has not posed a barrier to expansion of renewables.

CONCLUSION

In conclusion, attention to three primary areas is needed to ensure that variability is not a barrier to widespread implementation of distributed RE. First and most importantly is a common understanding of how variability occurs, how it scales, and what can be expected to occur as penetrations increase; and - at various levels of the utility system - what the impacts are, and what tools are available currently to manage these impacts. Doing so will require a balance between deploying appropriate technical solutions and tools, while avoiding well intentioned, complex technical "fixes" which are unnecessary and costly. Second, it is important that sufficient flexibility, operational practices, regulatory frameworks, markets, and tools such as accurate forecasting are in place to minimize additional regulation and load following reserves needed to manage VERs. Third: regulatory frameworks as well as codes and standards must proactively evolve to be more appropriate for integrating high penetration distributed generation, though this does not pose an immediate barrier; we should be proactive in creating the best environment for the aggressive pursuit of VERs in California.