A HUGE GAME CHANGER FOR utilities and possibly market operators will be the need to gain visibility and potentially control of hundreds of thousands of distributed energy resources (DERs). DERs can, and will, include photovoltaic (PV) generation, electric vehicles (EVs), demand response (DR), combined heat and power, storage, small-scale wind, and other technologies. Some might say that this is the province of a distributed energy management system (DERMS), but a supervisory control and data acquisition (SCADA) system with applications by any other name is an energy management system (EMS)/distribution management system (DMS)/DERMS or even a battery energy management system.

Widespread DERs create a number of technical and process issues that will stress today’s EMS/DMS architectures. First, the sheer point count will exceed the design goals of most, if not all, systems. This is not an unachievable requirement as today’s IT should have no trouble with the kinds of limitations that taxed the 16-b real-time SCADA systems of 40–50 years ago. It may stress some particular software designs, especially ones that carried over details from those old systems. The basic SCADA functions of get data, alarm data, and store/display data are amenable to parallelization, so performance should also be manageable, assuming the system software architecture in question will allow parallelization, which is another question altogether.

The scale and performance issues begin to bite harder as you move up the analytical food chain. Incorporating all those DERs in a distribution network model for an advanced distribution management system could lead to a million-node load flow with possible optimization or management of those hundreds of thousands of DERs. Again, this can be in parallel if the network is broken down at the transmission-distribution boundary. This is actually doable today; so again, this may not be an issue. Integrating that model with transmission analysis functions is another degree of difficulty, and this poses mathematical/algorithmic challenges as well as performance problems.

At the extreme, representing and optimizing the DERs in a set of market analytics is definitely not feasible today. Today’s mixed integer programming (MIP) engines, depending upon the details of the system, are close to the edge of what can be solved within a market-clearing window of an hour, and adding one or two orders of magnitude to the problem, could be the death knell. Aggregating the DERs helps, of course, but already aggregators are lobbying for the ability to aggregate resources across multiple distribution circuits or stations, which defeats the purpose from the MIP engines’ viewpoint.

The industry has always faced performance problems, however, and always managed to somehow keep the problem requirements within the reach of affordable architectures. It could be possible that someone will crack the nut of parallelizing the optimal power flow and security constrained unit commitment problem; someone may figure out how to use high-performance graphics CPUs for these applications instead of general-purpose chips. We have to have faith that performance issues that appear impossible today will be solvable within a decade, if not sooner.

A more challenging problem, in my mind, is the need for a different paradigm for database management. At the one extreme, new transmission construction is planned years in advance, and the network models for new transmission are known months in advance. At the transmission or independent system operator level, databases can be prepared, tested, and ready to go when the new line is energized. Outages occur within the domain of existing switchgear and are handled by topology processing. The number of new changes is entirely manageable in a manual process.

The distribution world is different as changes happen daily and in sizable numbers. Utilities already put considerable effort into capturing planned and unplanned work on a daily basis and keeping databases current within a day or so. This requires coordination of DMSs, outage management systems, asset management.

(continued on p. 106)
systems, geographical information systems, and other distribution control room IT. Not every utility is achieving this “current daily” goal, and any utility faced with a major outage taking days to restore will fall behind.

Now add DERs to the mix. Today, installing a PV system requires an interconnection request and approval (and the delays in this process are major customer dissatisfaction points). But what about when the customer brings home a new EV with a charger? Or simply configures a state-of-the-art smart thermostat that is capable of taking DR signals? Today’s way of handling interconnections, new apparatus, and databases simply won’t fly. Customers are accustomed to online real-time updates of all sorts of Internet-based things: bank accounts, cable system subscriptions, even (fingers crossed) new Wi-Fi printers.

So the future “XMSs” (with the X representing whatever management systems) is going to have to incorporate the “self-announcement” of DERs. The DERs will connect, possibly via the Internet, with a utility IT system and basically say, “Hi, here I am. I’m a model 7735 EV with 65-kWh batteries capable of charging at 200kW and discharging at same. I live at 4545 Mercer Way, and my license plate is 3XYZ123. Please credit DER revenues to my bank account ######.” That utility IT system is going to have to then update databases for all the different XMSs and ensure that things work smoothly. It will probably have to go back to the EV and do some tests to make sure things work.

You can imagine the same for PVs, storage, whatever. I picked EVs to talk about because that creates a different problem—mobility. Today the charging station providers manage the financial end of that just like credit cards, affinity programs, and a zillion other consumer business processes are managed. But they don’t have to tell the utility anything at all about what is happening at the charger located on Walker St. at the 14th parking meter down from the corner.

Utilities today live in a world where database changes are manual or semi-manual, interconnection requests take weeks if not longer, there are relatively low numbers of these, and integration with aggregator databases is primarily around metering and DR measurement and validation, not control. Customers have been spoiled by other industries into thinking all this can, and should, happen relatively painlessly and in relatively short time frames. There are industry groups working on the business process “use cases” for DER integration and on the data definitions and content. But are we ready with the IT architectures to handle it?