Unlocking Customer Value: The Virtual Power Plant

How does a utility manage the complexities concerning the rollout of pricing, demand response and distributed energy resources for load reduction, ISO/wholesale market participation and/or distribution management? One way is through the use of Virtual Power Plants (VPPs).

By Aaron Zurborg

The utility world has changed drastically in the last 10 years. New technologies like *Smart Meters* and fully functional *Smart Grid* concepts have made large inroads into the utility space and no one should want to be left behind. Utilities also face additional pressures from regulatory bodies who are continuing to encourage carbon reduction and greater customer flexibility. Utilities need to balance these new requirements with the financial obligations of providing reliable power (at a reasonable price) while attempting to meet shareholder expectations. Each of these goals are not necessarily complimentary, thus utilities need to determine how to address each one.

Some of the ways utilities are addressing these concepts is through the rollout of dynamic pricing for reducing peak-load, demand response to shed load during emergency situations or other trying times, large scale distributed generation to reduce usage of fossil burning plants, localised distributed generation or demand response to improve grid balancing or reduce outages, and leveraging Independent System Operator (ISO)/wholesale markets where utilities bid customer demand response or distributed energy resources into the market. While each of these present great opportunities they are also riddled with challenges. Issues arise from how to forecast appropriately the level of customer participation in programs, how to include demand response or distributed energy resources into a utility's operational portfolio, and how to execute very localised demand response to address grid specific issues. Each of these challenges are complex and while not all opportunities will be addressed by each utility, any combination of each of these will require a solution that can address operational concerns of how much load will be reduced and how does that impact a utility's procurement/generation of power. How will demand response impact a utilties distrbution system, and in what ways can a utlity aggregate these available customers into something that makes logical sense. This paper explores one concept to confront these challenges which is the *Virtual Power Plant.*

Smart Meters, Dynamic Pricing & Demand Response

In the United States alone there is the pressure of thirty eight plus commissions looking to enforce new Smart Grid AMI and Demand Response (DR) implementations, along with Presidential expectations of a rollout of 140 million Smart Meters by 2019.[1] While utilities continue to rush to meet these demands, they also need to consider how best to achieve the full return on their meter investments. AMI implementations are normally funded through rate adjustments, or board approved capital expenditure projects that are justified through the benefits of remote readings, connects and disconnects. Those benefits only scratch the surface of the benefits that smart meters can provide. Many utilities are evaluating other benefits, whether that be through load reduction from new DR programs, or dynamic pricing programs that will shift or reshape load, reduce peak periods, or contribute to spinning reserves.

Southern California Edison has included a benefit for their Phase II smart meter rollout – an expectation of 1,000 MW of peak-load reduction through DR and pricing programs that become available through the smart meter rollout.[2] Include in-home displays, in concert with pricing programs, and a utility can achieve so much more.

A recent study by the Brattle Group on dynamic pricing found that across the US critical peak pricing programs induced a drop in peak demand/usage by 13-20%, while Peak Time Rebate (PTR) showed a drop in peak demand of 8-18%. With technology in place to respond automatically to Demand Response, these falls increased to 20-45%.[3] The findings are significant to any operations organization and cannot be ignored when included within the utility's overall generation portfolio plans. Through these studies and existing programs, utilities now have the ability to utilise DR and pricing programs to consistently reduce or shift peak demand, offset intermittent renewables, relinquish short-term contacts and even utilise them to contribute to spinning reserves.

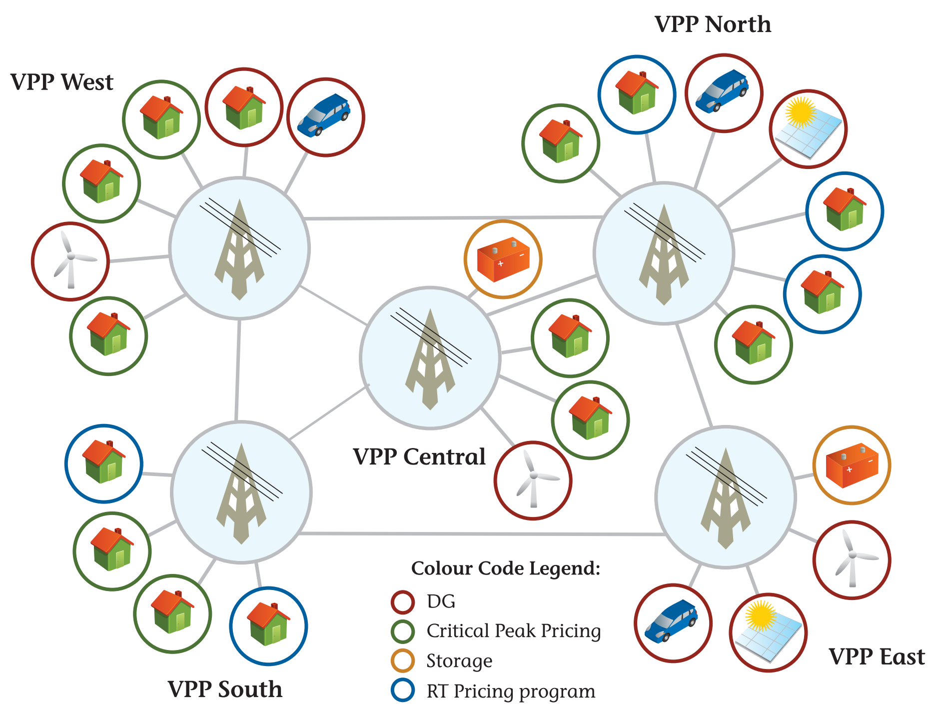
> ... utilities need to also consider how best to achieve the full return on their meter investments

Wholesale Markets & Demand Response

Markets are encouraging bidding of DR into their wholesale or retail markets. Since 2006, the DR contribution to peak-load reduction within the ISO/wholesale market in the US has increased by 10%. Even in Europe, wholesale markets are looking at how to increase the ability to bid DR into their respective markets. As utilities begin to participate in ISO bidding strategies they are not only seeing the benefits, they are also understanding the challenges.

The biggest challenge that utilities face of market bidding is the relationship between the physical and financial models. Bidding into an ISO, utilities are supplying a financial bid of price and MW quantity to the ISO market. This bid is based on the defined Locational Marginal Price (LMP) which is defined by the ISO. While this makes bidding consistent in

Figure 1: Aggregations of Demand Response & Distributed Generation



the ISO/wholesale market, it creates a significant challenge for the utility once they are awarded the bid. They have to call upon these participating customers not on the ISO model, but the actual physical topology of the customers in the utility distribution model. This mismatch of relationships can be a challenge in everything from forecasting available DR to customer selection once awarded and physical/financial settlements. With forecasting, utilities need a way to ensure that they achieve the optimal benefits and avoid leaving money on the table where they under forecast their ability due to risk avoidance from unsure accuracy in their forecast. Likewise, when unravelling the award from the ISO, utilities need a quick way to translate the financial award to an action that physically will not only select the appropriate customers, but will do so with minimal impact to their generation and distribution environments. Finally, during settlement, utilities need to reconcile payments between the ISO and the utility's customer. This meeting of the financial and physical markets, especially as the physical market becomes 'smarter', creates a new complexity that must be managed.

> The smart grid is revolutionising how utilities think about their existing distribution systems

Distribution Systems & Demand Response

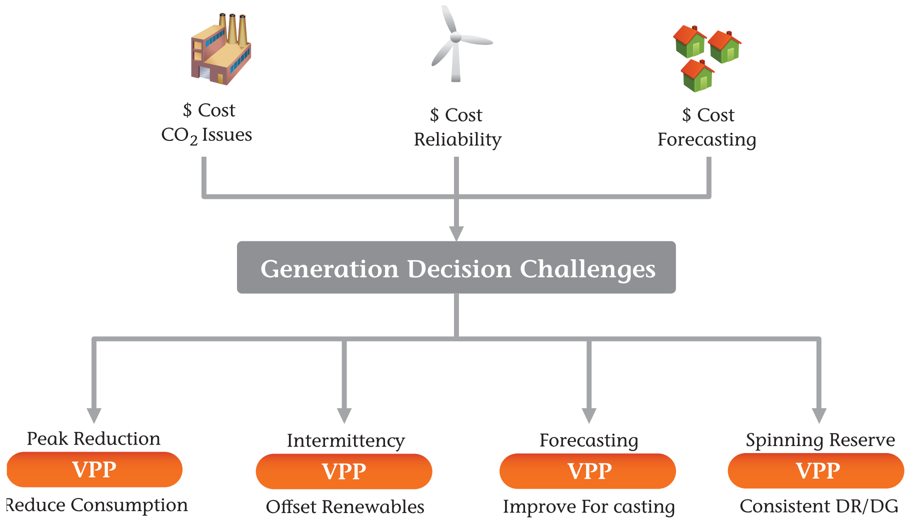
The smart grid is revolutionising how utilities think about their existing distribution systems. Everything from smart reclosures down to smart transformers is changing how the grid is monitored and epitomised. Include new distributed generation that is increasing in use from residential and commercial customers due to rebates and incentivised pricing structures, and the grid has become a lot smarter and volatile than it used to be. While this volatility can be a challenge, there are major benefits and challenges to a smart grid – and especially in concert with DR and distributed generation (DG). Adding large quantities of DR or DG to the grid can result in deficiencies that include a potential decrease in power quality, decrease in reliability, unbalanced power flow and potential risk to public and worker safety. While there is no question about the challenges of increased DR & DG, there are also significant benefits. This includes carbon reduction, which PECO expects to bring a reduction of 1M metric tons of CO_2 through their Smart Grid project, a reduction of outages (resulting in improved customer satisfaction), and the avoidance of regulatory penalties and extension of distribution assets.[4]

In order to address both the challenges and benefits, utilities will need to improve the way in which they monitor, forecast and match DR & DG against their distribution topology. Imagine if utilities could action DR at a distribution level to take advantage of addressing power flow issues, or outage avoidance. Likewise, if utilities could utilise localised DG to address grid challenges, or even produce power more cheaply in a localised communal area, this could save on the procurement of peak power. These concepts could be possible, but utilities need to be able to forecast, execute and respond in a much more granular way than most operate today. Utilities struggle with being able to accurately and continually identify the amount of DR or DG available at any given point of time and location. Overcoming these two barriers would allow utilities to take full advantage of their smart grid and DR &DG solutions.

Virtual Power Plant Value

So, how does a utility manage the complexities identified earlier in the paper concerning rollout of pricing, demand response and distributed energy resources for load reduction,

Figure 2: Renewable Intermittency



ISO/wholesale market participation and/or distribution management? One way is through the use of Virtual Power Plants (VPPs).

VPPs are an aggregation of customers (i.e. residential, commercial or industrial) under one type of ***Pricing, Demand Response*** or ***Distributed Energy Resource*** program. While that concept sounds very similar to today, the key differentiators is that a VPP is defined at a more granular level than just the overall program. No longer do utilities need to group all customers with a particular program under one umbrella. The VPP concept allows utilities to aggregate these programs by type and location in the distribution topology or some other agreed upon aggregation.

Why do this – grouping customers into segmentation based on specific geographic or distribution definition? Segmentation provides the utility with better forecast and analytical information about the value these particular customers (and ostensibly programs) can bring to the utility (Figure 1). Grouping also allows a utility to collect customers under the same program into different group structures based on the utility's needs. For example, the distribution organization may group customers into VPP's that fit their distribution model, while the retailers or generators group customers by city or some other higher–level aggregation. Providing the flexibility to group customers based on the business need provides a lot of added value that is not necessarily available today.

Providing segmentation not only improves forecasts but can dramatically improve operational decision making. Another component of a VPP is that it contains plant-like characteristics that mimic a traditional generation plant. An example of a plant-like characteristic includes where a DR program might stipulate that the utility cannot shed a customer's air conditioning unit more than once a day. This type of constraint would be an execution constraint. Other constraints could include a capacity forecast, customer payments (i.e. cost of running the program), opt-out limits and others. By assigning these attributes to an aggregation of customers under the same program, utilities can begin to determine which VPPs should be called upon against the rest of a utilities operational portfolio. Based on these decisions, VPP's can then be dispatched based on the pricing or environmental constraints as part of the utility's entire generation portfolio. In that respect, VPPs represent the next generation of DR as integrated strategic resources for the utility company.

No longer do utilities need to group all customers with a particular program under one umbrella

Dynamic Pricing & Demand Response with VPPs

Forecasting can be a difficult process across a major utility's geographical area, as residential and commercial customers (and their participation) vary greatly. A very good example is customers in Colorado Springs react quite differently to prices for the same program than customers 100 miles away in Boulder. While the physical gap is small, residents' philosophies are significantly different due to socio-economic factors, regional weather patterns, even political views. Aggregating all of these customers together into one forecast limits the ability for utilities to truly understand which customers may be more reliable in program participation compared to others. VPPs can reduce the forecasting risks that utilities feel today. A utility can create VPPs that aggregate each available program at a distribution level or some other smaller geographic area. This means for each type of pricing, DR or DG program there would be a VPP for each commercially significant transmission zone or region. Each VPP would have a specific forecast for each program type and region. This more granular forecast would not only provide more accuracy in the forecast but also identify those VPP's which more consistently participate when called upon.

While improving forecasts gives utilities a better idea of price responsiveness to particular programs, the real challenge is how to choose to operate your generation in concert with the load. When optimising the portfolio, utilities should include pricing as well as direct load control programs as part of that optimization. Utilizing the concept of VPPs allows generation and integrated utilities to treat them as another operational plant, with standard attributes including maximum capacity, minimum capacity, ramp-up, ramp-down, etc.. And based on those defined parameters utilities can optimise their entire portfolio and determine how to leverage DR or DG to reduce/shift peak loads, reduce generation costs, and reduce emissions. The concept of a plant like DR or DG can become extremely valuable as intermittent renewable resources continue to grow requiring utilities to provide spinning reserves to address their intermittency (Figure 2). Leveraging these new VPP's, utilities would no longer have to run typical generation plants and instead could action reliable VPP's/customers to either curb load or produce clean localised generation.

For distributors and retailers, utilising VPPs can modify the entire business model. No longer do ***generation companies*** own plants, now ***retailers*** own entire sets of virtual plants that they can leverage against the ISO/wholesale market to avoid high power procurement costs or utilise customers to bid into the ISO/wholesale market.

VPP & ISO/Wholesale Markets

The VPP concept can overcome the chasm of the financial and physical models for ISOs. As discussed previously, VPPs can allow for the flexibility to define these at whatever topological level desired. This flexibility allows the utility to play in both the physical and financial markets. This concept is important as a utility bidding into an ISO/wholesale market is interested in how its bid equates to the other potential bids within the market. The ISO/wholesale market also wants to understand how the utilities' bid fits the overall pricing structure offered. However, the utility – once it solidifies an award – wants to know how to select the right customers based on DR program business rules and their availability. The utility also needs a way to perform an appropriate analysis of customer participation; and payout and balance its distribution system based on its participation in the ISO/wholesale market. These varying goals can be accomplished by tying these components together into one Virtual Power Plant. So how do utilities do this?

Let's say, for example, that the utility has a current A/C Load Control program that covers the entire utility area. With this program, it is getting DR results, but realises this does not translate very easily to the ISO market due to inconsistent response or forecasting. To initially deal with this issue, the utility may first define a VPP that equates to a distribution topology. The utility has now taken one program and dissected it into multiple groupings of the same program. Doing so provides the utility with a more accurate forecast of available resources and perhaps due to specific conditions in the area, a more consistent participation when the Load Control program is called upon. Knowing which areas/customers that participate more consistently will help the utility decide which physical VPPs (or in reality groups) of customers within the distribution topology the utility would feel confident about bidding into the market.

> ... utilities can define VPPs that relate directly to the distribution model

Now that the utility has some confidence in its programs and groups of customers participating, it needs to translate this into a bid that fits the ISO/wholesale market topology, while ensuring that it has enough available DR from these physical VPPs to bid into the market. To do that, the utility would create a separate VPP that has been defined by the ISO/wholesale financial topology. This financial VPP can have one or multiple physical topology VPPs tied to it.

As already discussed, by having physical VPPs that aggregate within a financial topology the utility is only forecasting and bidding those customers into the market that it feels can consistently participate when called upon. The utility, in submitting the bid, has met the rules of engagement from an ISO topology perspective, but has also translated for itself the actual customers and distribution channels that will physically participate if selected by the ISO. Once the award has been granted, the utility will have an easy time disaggregating the request down to the customer and distribution level, as it has already created the physical and financial relationship that ties the ISO topology to the physical customers within the utility.

The flexibility of the VPP for ISO/wholesale bidding means

Figure 3: Physical & Financial Topology

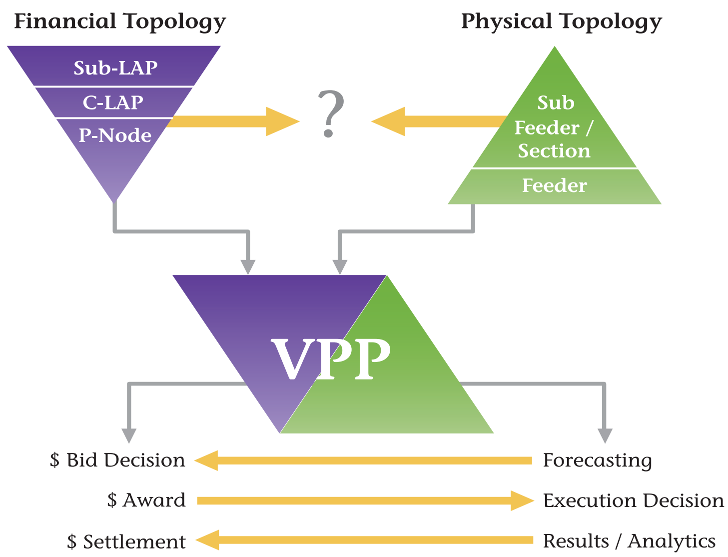
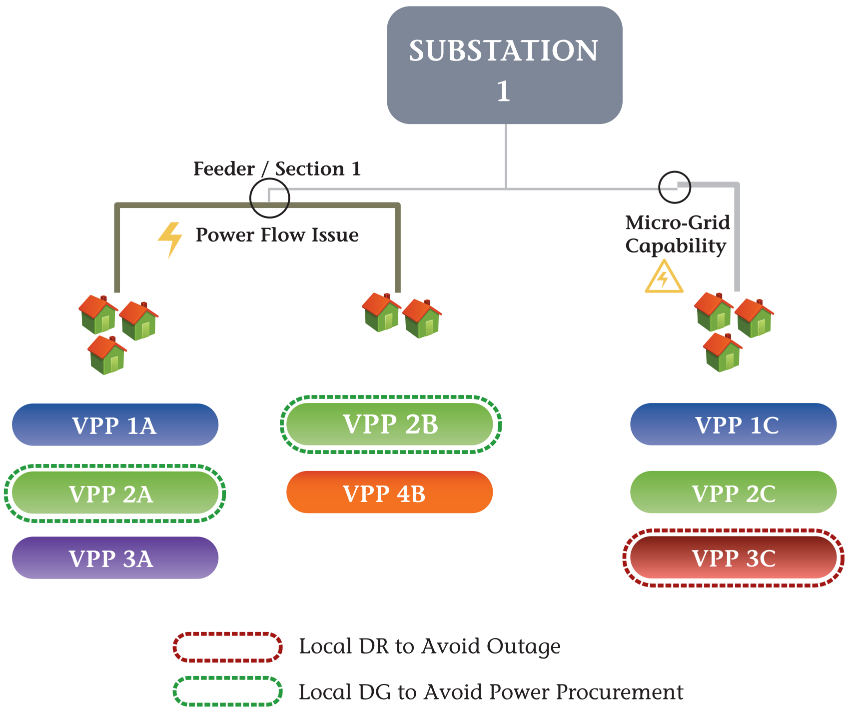


Figure 4: Creating VPP Substations



that to bid DR into the market utilities don't have to necessarily create new programs that are emergency response focused (i.e. programs that create large penalties if customers don't participate). Instead, they can leverage their existing programs and select/choose groupings of customers that provide enough consistency that the utility can feel comfortable with bidding them into the market. Moreover, leveraging any day-ahead market awards that the utility receives, they can do a better job in forecasting both the generation and distribution system, as the direct linking between the physical and financial topologies allows them to know who and how much load is being shed tomorrow and the impact on the distribution system. These benefits, along with the ability to reconcile physical and financial settlements, can greatly improve a utilities regulatory commitments and financial incentives.

Distribution Systems & Virtual Power Plants

Utilities can, therefore, define VPPs that relate directly to the distribution model. For example, a utility can create a VPP for each substation, feeder/section or even transformer (Figure 4). Each VPP would contain one program that is modelled with customers for the defined distribution area. Just like an operational VPP, the utility would produce a forecast for each VPP within the distribution model. This information can become invaluable if the utility is able to link these to its Supervisory Control and Data Acquisition (SCADA) or Distribution Management System (DMS). For each feeder/section the utility could have a real-time, hourly or daily availability of a VPP of DG and/or a VPP of DR at each feeder section. When a power flow issue occurs or a potential outage is identified, the SCADA/DMS system could execute the appropriate VPP to help address the power flow issue. As the execution occurs, the VPP – through smart meters or other mechanisms – can directly feed the SCADA/DMS system with the actual results achieved. Likewise, modelling DG as VPPs within the distribution level (and inclusion of its forecast) would help the utility predict when DG could create an imbalanced distribution system, or when it could be dispatched to provide localised power when generation prices are high. Because VPP's can be aggregated at various levels they can be used for both grid reliability as well as operational optimization.

Outcomes

As ***Demand Response***, ***Pricing Programs*** and ***Distributed Generation*** continue to grow utilities need ways to manage their complexity and leverage their capabilities. Each type of utility faces various challenges to the business but with VPPs utilities can address some of the most pressing issues.

– VPPs work for ***retailers*** to drive down procurement costs and keep customer rates low through aggregation DR and DG to offset power procurement and bid demand into the market.

– VPPs work for ***distributors*** by aggregating at a distribution level DR and DG can balance the grid, avoid outages and extend asset life.

– VPPs for ***generation*** can aggregate DR and DG and optimise these plants with its standard portfolio to reduce peak periods, contribute to spinning reserves and offset renewables. ■

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Ventyx was recently acquired by ABB, the global power and automation technology group
www.ventyx.com

Footnotes

1. FERC 2009 Assessment of Demand Response and Advanced Metering.
2. SCE CPUC Filing for Phase II Smart Meter Rollout 2007.
3. Unlocking the 53 Billion Savings from Smart Meters in EU, Ahmad Faruqui, Dan Harris, Ryan Hledik.
4. Smart Grid Proposal to DOE – PECO Smart Future Greater Philadelphia.