High-Definition Modeling of Electric Power Delivery Networks

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***Abstract*— This paper discusses the experience of work (Project) funded by the California Energy Commission (CEC), performed by New Power Technologies (NPT), and hosted by Southern California Edison (SCE), showing that Energynet® high-definition power delivery system simulations integrating distribution, local transmission, and regional transmission in a single high-definition model with 2-3 orders of magnitude additional detail provide new, useful insights into the behavior of the power delivery system. New Power Technologies provides an overview of their high-definition modeling-based methodology applied to SCE's largest regional distribution power delivery system, the Hobby system, consisting of local transmission loops, 54 substations, 215 distribution circuits, 45,916 customer sites, and a peak load of about 1,350 MW. SCE puts the accomplishment and additional insight of enhanced high-definition modeling into context of present practice and potential future planning and operation applications.**

Index Terms—Circuit Optimization; Deductive Databases; Load Flow Analysis; Lossy Circuits; Optimal Control; Power Distribution; Power System Simulation; Power Transmission; Voltage Control

I. INTRODUCTION

As demonstrated in the Project, high-definition Energynet® network-wide power system models representing 2-3 orders of magnitude more detail than conventional practice are practical; they can be developed from readily-available system information, and they integrate data from and interoperate with legacy outage management, SCADA and customer systems. Highly-

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detailed models with node counts exceeding 100,000 buses were used and are supported by commercially-available system analysis packages including an enhanced version of General Electric's PSLF and Optimal Technologies' AEMPFAST™. Such simulations show conditions and behavior of system elements from the overall planning area power system level to individual components and line segments within individual circuits. Such a detailed simulation augments field system instrumentation whether rich or sparse -- field-read data gains system level context and also help to inform and refine the simulation. Moreover, such a simulation can reveal conditions in system areas with little or no field instrumentation. In planning the local and system-wide impacts of load relief projects can be directly observed. Used in conjunction with advanced analytical software such as AEMPFAST, such simulations can be used to improve network performance through optimized controls, topology, and resource additions. Populated with actual load data for a variety of operating conditions, such simulations extend engineering studies beyond just peak loading conditions, enabling a distinction between persistent and situational concerns. The combination of element-level detail and system-wide scope can help bring focus to issues in a far-reaching, complex system, such as identifying the 2-3% of all system elements whose loading represents the most immediate threat to reliability, the 5% of line segments responsible for 95% of system-wide losses, or the 2% of circuits with low voltage under both summer and winter peak conditions. A key focus of this work has been to rigorously determine the potential for distributed energy resources to enhance grid performance or avoid expansion projects. Ongoing work will validate the data interpolation, extrapolation and infill required to practically develop such a model with field measurements. This ongoing validation effort will also demonstrate rolling updates of the high-definition simulation to support operational decisions.

The following summarizes our experiences in developing and using the high-definition Energynet model, performance of analyses using the model, results and findings, plans for model validation, and conclusions.

II. HIGH-DEFINITION MODEL DEVELOPMENT; SOURCE DATA-TO-MODEL

The original impetus of high-definition power system modeling was to directly observe the local and network-wide impacts of distribution-connected devices and elements, with a particular focus on distributed energy resources (DER). In our view capturing local and network-wide impacts would require modeling the power system without approximation, in full detail, but also encompassing the entire interconnected network. Accordingly, high-definition power system modeling comprises integrating distribution and transmission into a single model, with elements discretely incorporated down to the individual distribution device and line segment level. Such an approach results in power system models having 2-3 orders of magnitude greater detail than conventional practice. New Power Technologies refers to such a model as an Energynet system model. Such an approach was first demonstrated by New Power Technologies in an earlier

CEC-funded project dealing with a smaller, less complex power delivery system. One objective of the subsequent Project was to demonstrate the practicality of this type of modeling for the larger power delivery systems characteristic of California’s investor-owned utilities—that is, to demonstrate that for such networks Energynet models could be developed with existing data and reasonable effort.

SCE’s existing power flow model of the subject system, SCE’s “Hobby” system, incorporated only local transmission-level elements, comprising approximately 30 individual nodes or buses. We found that the distribution elements of the Hobby system were well-documented in several sources that are commonly maintained by utilities, including substation single-line drawings, a company-wide substation table, circuit maps depicting field information and those supporting the company’s outage management system, and a database of distribution-connected generation units derived from interconnection requests. We determined early on that manual development of the distribution portion of the model, the approach used in the prior project, would be wholly impractical, as many of the Hobby system’s 200+ circuits included 1,000 or more elements *each*.

We also found that while accounting for all the elements in the subject system represented one level of difficulty, incorporating them in a fully-connected system-wide power flow model, with correct topology and no islands or spurious ties or loops, would represent a vastly greater level of difficulty. While these issues are readily resolved by a human with deep knowledge of the subject system, in a system this size resolving each question by hand would also be impractical. One consideration was whether to develop a 3-phase model of the subject system. In this case individual phase data were not available, so we did not pursue that approach.

The Project thus included a major effort to demonstrate automated software means to ingest and interpret system data from the utility, identify and resolve discrepancies among sources, employ context-sensitive infill for missing data, and apply various tests to determine the correct connection points within the network topology for individual unconnected elements and islands. Only about 60% of the data in the final model were incorporated from the source data without any infill or manipulation in the software. At the same time, while we had hoped to reach fewer than 100 nodes with issues requiring human resolution, or 99.9% successful machine processing, we actually ended up with only about a quarter of that number, surpassing our goal. Once these few remaining issues were resolved, we integrated the Hobby system’s distribution and local transmission with regional transmission modeled in the West-Wide System Model of the Western Electricity Coordinating Council into a single power flow dataset comprising over 100,000 buses. To demonstrate the practicality of these data processing tools, we also produced from different source data a model of a second SCE system in a month and produced a second model of the Hobby system with replacement source data, updated after two years, in a week.

One consequence of the size of the Hobby system was that the integrated power flow dataset, at over 100,000 buses, was well beyond the capability of most widely-used power flow packages. GE Energy developed for us an enhanced version of their Positive Sequence Load Flow (PSLF) software capable of handling datasets of up to 150,000 buses. The power flow component of Optimal Technologies' AEMPFAST power system analysis software was also able to handle this dataset without difficulty.

To simulate the behavior of the modeled system under actual load conditions that might be encountered during a year, we populated the model for real and reactive loads at each load-serving site with load data derived from SCADA archives for a range of conditions. We chose a super-peak condition (one of the highest-load hours of the year), a more typical summer peak condition, a winter peak condition, and a minimum load condition. We developed a case using the light load hour of the super-peak day for diurnal studies. Considerable infill was required for those circuits without full circuit-level current and power factor SCADA reads. All loads were corrected for capacitors reflecting condition-appropriate dispatch and embedded generation as well as for loop-fed and radial secondary and tertiary substations.

The Energynet model is a buses, lines, transformers, and resources model that supports power flow applications. Its normal power flow dataset format is GE's "*.epc" format, and it can also be directly read into AEMPFAST. However, the Energynet model also incorporates all of the engineering detail of each element from the source data, all of the existing instrumentation and control sites, and the rate schedule and other customer information at each customer site. All of the information is extensible and interoperable with the SCE data systems from which the source data were drawn.

III. HIGH-DEFINITION MODEL ANALYSIS

We were able to obtain power flow solutions for the Energynet model using AEMPFAST and enhanced PSLF. We found power flow feasibility very sensitive to the modeled tap settings of individual transformers and voltage regulators; in fact we had to set the taps to match very closely the operating voltages used by SCE simply to obtain a solution. Very low-impedance model elements such as short distribution line segments did not appear to prevent a power flow solution.

A power flow solution will of course provide voltage and real and reactive power flow at every location within the model. Power flow results from a high-definition integrated distribution model can be particularly revealing due to the potential in the distribution system for large localized variation in power flow and voltage combined with relatively sparse field monitoring. From a system comprised of hundreds of thousands of elements, power flow results from a high-definition model can quickly and systematically distinguish the regions, circuits, or individual buses and elements of interest. As expected, we found far more variation in voltage in the distribution portion of the system under all load conditions. Fig. 1 compares transmission-only and integrated transmission and distribution (Energynet) system voltage under four different sets of operating conditions. The voltage in per-unit terms (right scale) averages around 1.0 under all conditions for both systems, and in the transmission system the maximum and minimum voltage lie well within the desirable +/- 5% range. However, with the distribution system incorporated in the Energynet model, even though voltage still averages around 1.0 PU, the maximum and minimum voltage cover a far greater range, and under winter peak, summer peak, and super peak conditions the system-wide minimum voltage lies outside the +/- 5% range. The voltage variability (left scale) is also greater in the Energynet system than in the transmission system alone under each set of conditions.

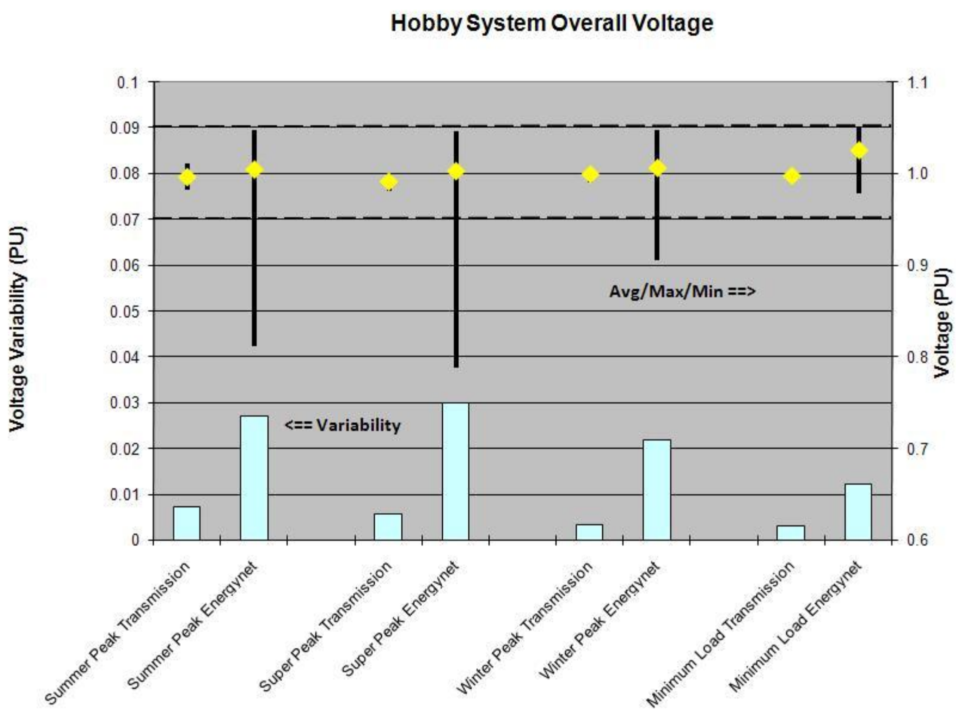

Figure 1: Per-Unit Voltage (right scale) and Voltage variability (left scale) for Hobby System comparing transmission only with integrated transmission and distribution (Energynet) under summer peak, super peak, winter peak and minimum load operating conditions.

The high-definition model directly reveals low-voltage regions in the system or even within a circuit as well as circuits with significant voltage drop. Also, the use of a range of load conditions permits distinction of seasonal or intermittent low-voltage conditions from persistent low-voltage conditions. We identified low-voltage buses in several Hobby circuits under one or more operating conditions, and five Hobby circuits with voltage drop exceeding .10 PU (i.e., circuits that cannot maintain all points within a +/- 5% PU voltage range). Moreover, as three of these five are served from substations not equipped with instrumentation, the model reveals circuits of interest where field instrumentation may not. As one interesting voltage profile example, Fig. 2 shows the voltage profile of a Hobby circuit with a highly-localized low-voltage condition. The voltage is elevated at the substation to about 1.04 PU, it is boosted within the circuit by a voltage regulator, it and remains above 1.0 PU at the far end of the circuit. However, within the circuit just, upstream of the voltage regulator, voltage falls below .95 PU under summer peak and super peak conditions.

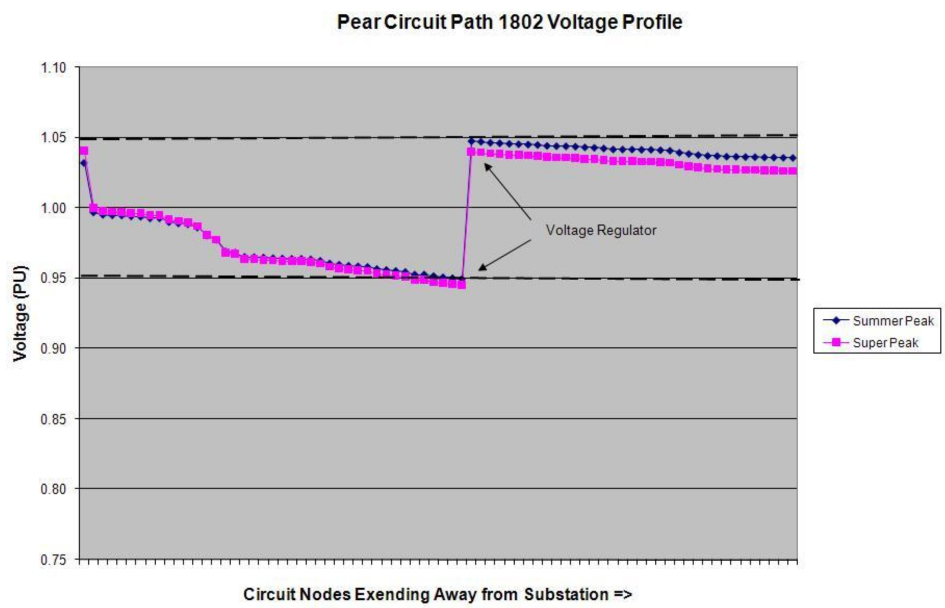

Figure 2: Pear Circuit Path 1802 Voltage profile extending from substation under summer peak and super peak operating conditions.

The high-definition model directly reveals losses across each line segment of the system. As expected, we found higher system-wide losses under heavier load conditions. We also found that 5% of the system's line segments account for 95% of the system's losses. However, these "lossy" lines are not localized; nearly every circuit had some lossy lines. What these lossy lines have in common and whether there is an opportunity for significant loss improvement within this small share of the system's line segments is an interesting topic for further inquiry.

The high-definition model also directly reveals loading of each individual element relative to its normal and emergency ratings under all of the conditions modeled. We used this capability to systematically identify the very small share of the system's circuits whose loading legitimately represents potential near-term reliability concerns. We were able to identify circuits that, while heavily-loaded, were well within their normal ratings under all but super peak conditions. Nine of the 215 Hobby circuits have peak loads exceeding 550 Amps. However, of those, only four had individual line segments loaded at greater than their normal rating under summer peak conditions. We were also able to identify circuits with more modest loads but that did have individual segments with loads exceeding their normal ratings under daytime peak conditions throughout the year. We identified eight Hobby circuits with elements loaded at over their normal ratings under both summer peak and winter peak conditions. Given an assumption that that an element loaded at 120% of its normal rating has a 10% greater failure rate we were able to directly apply this type screen to every line segment under all conditions for a systematic system-wide identification of reliability risks, identifying 12 Hobby circuits with elements loaded at over 120% of their normal rating under summer peak conditions and 17 such circuits under super-peak conditions. Again, several of these circuits lack circuit-level current monitoring, so these conditions may not be readily apparent from field monitoring data. We also identified circuits with elements loaded at greater than 65% of their emergency ratings under a presumption that these circuits had restricted ability to accept post-contingency load shifts. There are many such circuits; however, we identified 51 such circuits whose loading leaves circuits they back up with fewer than two alternative feeds; that is, where the inability of loaded circuits to accept load shifts could actually affect outage duration. Further, of these 51 circuits, eleven would have restricted ability to accept load shifts following outages under both summer peak and winter peak conditions. Such systematic culling to identify a small number of circuits with real reliability risks permits the utility to direct remediation measures to where they will yield the greatest near-term benefit.

We employed Optimal Technologies' AEMPFAST power system optimization software to assess opportunities to improve the voltage and loss performance of the modeled system. We first used AEMPFAST to determine the ideal dispatch of the system's 103 transformer and voltage regulator taps, 839 station and line capacitors, and the reactive power output of 13 of the 26 distribution-connected generators. For purposes of the study we considered all taps as variable, all capacitors as switchable on-off, and all synchronous DG VAR output as system-controllable within a range. We found that through redispatch of these resources there is an opportunity for significant improvement in low-voltage conditions and loss reduction under both peak and off-peak operating conditions. To reflect condition-appropriate dispatch, initial capacitor dispatch under each set of conditions had been derived from capacitor type (fixed, switched, or automatic), time of day for the case, and individual device status reads from SCE's Distribution Control and Monitoring System (DCSM). Under AEMPFAST approximately 30% of the modeled capacitors were redispatched either "on" from "off" or "off" from "on" from their initially modeled status; the largest number of changes from the initial dispatch occurred under winter peak conditions. We also found that about 15% of the system's capacitors would not operate under any of the conditions we modeled if optimally dispatched. As shown in Table I, optimal redispatch of these resources under AEMPFAST yielded increases in the system-wide minimum voltage as well as reductions in voltage variability, and loss reductions under both light and heavy load conditions.

TABLE I

IMPACT OF OPTIMAL REDISPATCH ON HOBBY SYSTEM MINIMUM VOLTAGE AND LOSSES

	Vmin	**Local Transmission Losses**	**Distribution Losses**
Summer Peak	+ .047 PU	- 1.280 MW	- 1.958 MW
Super Peak	+ .036 PU	- 0.589 MW	- 1.856 MW
Winter Peak	+ .046 PU	- 0.254 MW	- 1.050 MW
Light Load Hr of Peak Day	+ .007 PU	+ 0.002 MW	- 0.407 MW
Minimum Load	+ .006 PU	+ 0.028 MW	- 0.310 MW

We next used AEMPFAST to help identify the location, size, and operating profile of a portfolio of potential DER additions (capacitors, demand response, distributed generation, and storage) that would yield the greatest improvement in the voltage and loss performance of the system – the so-called Optimal DER Portfolio. AEMPFAST assesses the sensitivity of the system's performance to incremental real or reactive capacity added at each node in the simulated network. AEMPFAST can be run to yield a rank-ordered listing of beneficial real or reactive capacity additions by size and location under a given set of operating conditions. Because the high-definition model includes information on every node in the system, including the rate schedule and load at each customers-serving transformer, we were able to further specify capacity additions as demand response (DR) and distributed generation (DG) additions appropriate for the underlying customer at each location to produce a realistic portfolio of potential projects. For example, a residential customer site where incremental capacity would benefit system performance might host 2 kW of DR through AC cycling and/or a PV system sized at half the customer's peak load, while an industrial customer site might host DR of up to 15% of its peak load and/or onsite generation amounting to hundreds of kW, up to 60% o the customer's peak load. We also assumed only relatively large customers (> 200 kW peak load) would utilize synchronous generation with VAR capability. Smaller units would be inverter-based, with no VAR capability, or inductive, with a VAR load. We limited any DG addition to no more than 60% of the host customer's peak load. We also limited the total inductive and synchronous generation on a circuit to 60% of the circuit's minimum load to ensure the Optimal DER Portfolio generation projects would not create unanalyzed fault duties or potential post-transient energized islands. We set the storage portfolio at a fixed total size of 35 MW or about 2% of the Hobby system's peak load. We considered any physical structure an eligible site for capacitors or storage, and with some exceptions, all 45,916 load-serving sites as potential sites for DR or DG projects.

As the Energynet model incorporates loads reflective of a variety of operating conditions, we were able to assess the benefits of potential DER additions under each set of conditions, revealing projects providing benefits under conditions other than peak conditions, and also implying an ideal operating profile for each project.

It was usually the case that while essentially all beneficial resource additions would contribute to overall loss reduction, most of the potential system voltage improvement would come from a small number of the most highly-ranked DER additions. A typical example, Fig. 3 shows the Hobby system's overall minimum voltage under summer peak conditions following the stepwise addition of approximately 15,000 AEMPFAST-identified and ranked DG additions. The first 1,000 or so yield a disproportionate increase in the minimum voltage, while the remaining additions have little effect.

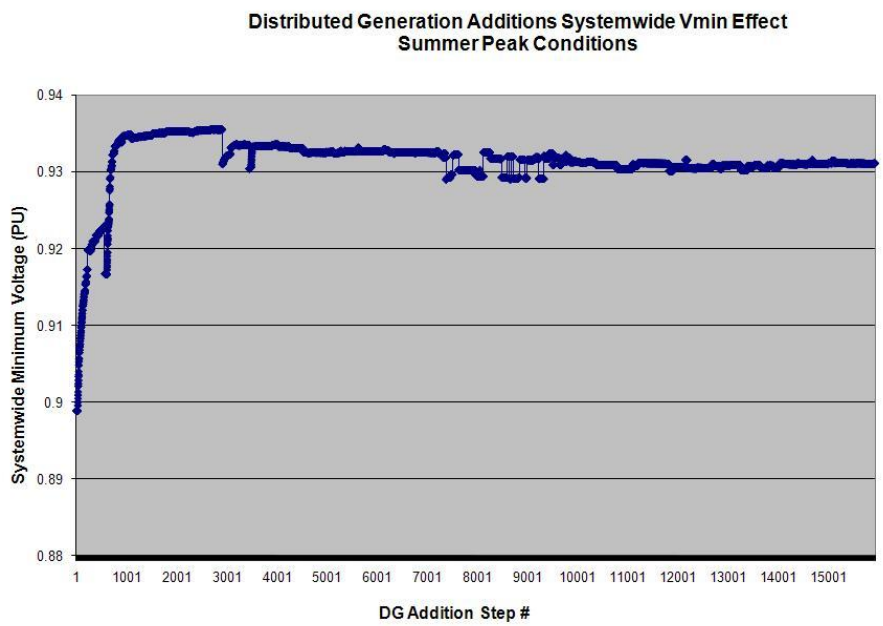

Figure 3: Sequential impact on Per-Unit system-wide minimum Voltage of approximately 15,000 individual DG additions under summer peak conditions.

Table II summarizes the makeup of the Optimal DER Portfolio for the Hobby system. The "Voltage Benefit Projects" are the subset of projects with disproportionate voltage benefits of the type described in Figure 3. We call out medium and large business DR projects separately as customers at these sites are more likely operate sophisticated on-site energy management systems that could provide more flexible DR under a wider range of conditions. Of the 19,381 DG projects, 17,070, or approximately 88%, are residential or small business PV projects. The remaining 2,311 DG projects are a mix of large scale PV, inductive generation, and synchronous generation at medium and large business customer sites. The majority of the storage projects are 10 kW, with a few as large as 60 kW. We actually found the smaller storage projects more beneficial as they could be sited where their capacity would yield the most benefit under peak load conditions, yet their charging load would still have modest adverse impact off peak. We actually found that unrestricted placement of storage projects as large as 60 kW could cause meaningfully adverse impacts—mainly localized low voltage—while charging.

TABLE II

ALL OPTIMAL DER PORTFOLIO PROJECTS AND VOLTAGE BENEFIT SUBSET

	Total Beneficial Projects	**Voltage Benefit Projects**
Capacitors	157 projects (42.2 MVAR)	22 projects on 11 circuits
Med. & Large Business DR	3,305 projects (9.8 MW, 50 MW super peak)	1,474 projects on 12 circuits
Residential and Small Business DR	18,842 projects (111 MW super peak)	3,000 projects on 58 circuits
DG	19,381 projects (318 MW)	1,396 projects on 72 circuits
Storage	1,488 projects (35 MW nominal on-peak capacity)	119 projects on 26 circuits

We also studied the 4,732 existing DR resources in the Hobby system that we had incorporated in the high-definition model. We found that even though these projects had not originally been targeted to provide network operational benefits, there are among these about 1,000 that have the kind of disproportionate voltage impact shown in Fig. 3, with a subgroup of 125 that are especially impactful.

Table III summarizes the combined impact of the Optimal DER Portfolio projects, excluding the storage projects but with the system's existing DR projects, on the voltage and loss performance of the Hobby system. As indicated above, virtually all of the voltage improvement is attributable to a small subset of DER projects. Most of the loss benefit is attributable to the DG projects because they represent the largest amount of capacity. The significant exception is the large amount of DR available under super-peak conditions, which accounts for a much larger share of the loss and voltage benefits under those conditions.

TABLE III

IMPACT OF OPTIMAL DER PORTFOLIO PROJECTS ON HOBBY SYSTEM MINIMUM VOLTAGE AND LOSSES

	Vmin	**System T&D Losses**
Summer Peak	+ .123 PU	- 19.284 MW
Super Peak	+ .144 PU	- 32.068 MW
Winter Peak	+ .004 PU	- 6.248 MW
Light Load Hr of Peak Day	+ .019 PU	- 3.980 MW
Minimum Load	+ .006 PU	- 0.200 MW

While the Optimal DER Portfolio projects were identified in this case specifically for their ability to provide loss and voltage benefits, the DER projects on specific circuits would also relieve some of the loading conditions described above, potentially reducing outage rates or durations in the Hobby system and increasing the load-serving capability of the system. The DR and DG projects also provide potentially valuable in-load-center capacity and energy.

IV. HIGH-DEFINITION MODEL RESULTS AND FINDINGS

The high-definition Energynet model of the Hobby system proved a powerful tool for assessing conditions in the Hobby system both overall and at the circuit or device level, even where field instrumentation is lacking. Perhaps more importantly, it can also serve as the analytical base from which to identify the small share of the system's circuits and elements where voltage conditions warrant attention, or where loading combined with topology could have potentially large influence on the network's reliability. Clearly the results described above are heavily dependent upon the quality of the source and infilled data used to produce the high-definition model, and independent verification of every piece of data would be an unreasonably massive undertaking. However, this type of analysis permits focus on the truly actionable findings and examination of the really consequential underlying data. For example, it is unrealistic and unnecessary to confirm the recorded specifications of 100,000 line segments, but it is entirely reasonable to verify a few dozen lines revealed in this analysis as representing potential overload conditions if they are catalogued correctly. Systematic, analytically valid identification of that small number of circuits and elements with the greatest potential impact on system performance can also bring focus to the complex issues facing such a large system and provide an objective basis for the highest-value project proposals.

Analysis aided by AEMPFAST showed opportunities to improve system voltage profile and reduce losses through redispatch of existing assets. The Optimal DER Portfolio identified a relatively small number of DER projects that could further improve system voltage and reduce losses. Moreover, it was clear that not all DER projects would benefit the power system equally. Certain identifiable projects in specific locations (and having specific sizes and operating profiles) demonstrably yield the greatest benefits. With this information, a utility is well prepared to respond to beneficial (or detrimental) DER project proposals by others or to investigate location-based incentives for beneficial DER projects.

V. HIGH-DEFINITION MODEL VALIDATION

The Project team is now deploying a field measurement system that will be used to generate field reads of power flow and voltage for comparison with results from the high-definition Energynet simulation. Every circuit in the system will be monitored for current and power factor, as well as voltage at several points along the circuit to provide a voltage profile. Each monitoring location is mapped to its corresponding node in the high-definition model. The monitoring network is based largely on SCE's existing SCADA and DCMS systems, but will be augmented where needed with specially-designed clip-on current and power factor monitors provided by GridSense, Inc. Data from all points will be gathered through a legacy communications network and presented at a single central location for immediate comparison with simulated results.

This system will be used to validate the high-definition Energynet model itself and confirm the impact of high-value resources predicted by the AEMPFAST software. For the model overall, our objective is to confirm that after all the processing and infill of source data and the extrapolation of substation-level load data, the high-definition system simulation is usefully representative of the behavior of the system it models and a valid starting point for further refinement. It also represents the first live demonstration of a power delivery system modeled in minute detail and monitored thoroughly and comprehensively such that conditions and behavior can be reliably examined at the level of individual distribution devices, resource, and customers. Operators might be able to test operating measures before they implement them or re-create and step through events after-the-fact.

VI. IMPLICATIONS FOR FUTURE PLANNING AND OPERATION

The initial focus of this work was to demonstrate a method to determine the potential for power system performance improvement from DER and to facilitate objective evaluation of DER as potential system improvement measures alongside conventional grid expansion projects. Beneficial DER projects, once identified, could be featured in targeted incentive programs or developed by the utility directly.

The high-definition Energynet model also offers an opportunity to enhance asset planning generally. At present asset planning is, out of necessity, based on a limited set of inputs and assumptions, and without the benefit of discrete knowledge of system conditions within circuits or in areas where instrumentation is sparse. Significant capacity may be left under-utilized, while other assets may be unknowingly stressed with accelerated loss of life. For example, detailed system modeling could be used to mitigate thermal stresses on specific line segments versus the gross circuit-level approaches now used. The same analytical techniques described here to identify optimal DER can also be used to optimize legacy assets such as shunt capacitors or even use existing DR resources as grid resources through targeted dispatch.

One of the features promoted by SCE in the model validation phase of the Project was the ability to update the simulation on an ongoing basis. If this is successful it offers potential that the high-definition model would be relevant in operational decision-making.

VII. CONCLUSION

The high-definition Energynet model, with circuit element-level detail in a system-wide model, can objectively and rigorously show the impacts of individual distribution-connected DER devices both locally within the circuit and across the system. Aided with powerful analytics such as AEMPFAST, this tool can be used to identify potential DER additions that could improve network performance. These fulfill the primary objectives of the Project. One of the most notable outcomes of this work is the ability of this type of analysis to bring to the surface key items of interest, such as the small number of “lossy” lines in the system, the small number of overloaded elements, or the small number of potential DER projects that yield the greatest potential network performance improvement. The high-definition Energynet model also offers an opportunity to enhance utility asset planning generally, and may be useful for operational decision-making.

A key objective of the Project, and a key consideration of SCE in its ongoing support of the Project, was whether such detailed system models are practical; that is, whether they can be developed with reasonably available data and within a reasonable time period, whether they could be kept up to date, and whether they are sufficiently accurate to be useful. In the work described here the Energynet model was shown to be practical, and the validation phase, if successful, will demonstrate the model to be usefully accurate.

VIII. ACKNOWLEDGMENT

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XI. BIOGRAPHIES

Peter Evans is President of New Power Technologies, a company dedicated to moving advanced energy technologies from theory to practical application. The company's Energynet® technologies enable power delivery network analysis and management with unprecedented transparency, precision, and ease of integration. Mr. Evans has extensive professional experience with electric power generation, delivery, and use, as well as power marketing, plant engineering, corporate and project finance, and energy technology commercialization, having held executive positions at Catalytica Energy Systems, Inc., Enron Capital & Trade Resources Corp., US Generating Company, and PG&E. Mr. Evans holds B.S. degrees in Chemical and Nuclear Engineering and an MBA from the University of California at Berkeley. Mr. Evans holds a U.S. Patent in distributed energy resources. He is a Professional Mechanical Engineer in California and a Chartered Financial Analyst.

Stephanie Hamilton is in charge of Distributed Energy Resources for Southern California Edison (SCE). At SCE, Ms. Hamilton oversees a diverse portfolio R&D of new and emerging DER technologies, such as concentrating solar, fuel cells, microturbines and balance of plant components such as inverters. Previously Ms. Hamilton held energy positions at some of the largest utilities in the US in both natural gas and power in both their regulated and unregulated subsidiaries, including Southern California Gas, Public Service New Mexico, and Grant County PUD. Ms. Hamilton holds an MBA and a BS in Mechanical Engineering and is widely published on energy and energy-related issues. Her latest book is The Handbook of Microturbine Generators. Meanwhile, she is an original member of DOE's 13-member GridWise Architecture Council which is focused on increasing interoperability in the North American power industry.

Tom Dossey is a Program Manager at Southern California Edison (SCE) responsible for the deployment of distributed energy resources to be used in support of SCE's electric systems. In addition to his responsibilities at SCE Tom is an active member of the California Energy Commission's "Distributed Energy Resources Integration R&D Program Advisory Committee" as well as its ongoing “Rule 21” Customer Generation Interconnection Workgroup supporting the California Public Utilities Commission’s actions related to distributed generation. Tom has served SCE for 42 years in a variety of roles, including Distribution Engineer, Protection Engineer, and Load Management Program Manager. Tom received his degree in Business Administration from the California State University at Los Angeles.