Millar, John; Saarijärvi, Eero; Müller, Udo; Fettke, Stephen; Filler, Marko

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IMPACT OF VOLTAGE AND NETWORK LOSSES ON CONDUCTOR SIZING AND TOPOLOGY OF MV NETWORKS WITH HIGH PENETRATION OF RENEWABLE ENERGY RESOURCES

John MILLAR
Aalto University – Finland
john.millar@aalto.fi

Eero SAARIJÄRVI
Trimble Solutions – Finland
eero.saarijarvi@trimble.com

Udo MÜLLER
Mitteldeutsche Netzgesellschaft Strom MbH – Germany
udo.mueller@mitnetz-strom.de

Stephan FETTKE
LEW Verteilnetz GmbH – Germany
Stephan.Fettke@lew-verteilnetz.de

Marko FILLER
Mitteldeutsche Netzgesellschaft Strom mbH – Germany
Marko.Filler@mitnetz-strom.de

ABSTRACT

This paper discusses heuristic distribution company planning rules, which are pragmatic but challenging to implement in a planning algorithm that aims to efficiently produce close to optimum solutions. The main focus is on how voltage is handled, and how other parameters, such as the cost of network losses and the time horizon used for planning, affect voltage. This is illustrated via Greenfield horizon plans and cost breakdowns based on a typical distribution network in the south of Germany.

INTRODUCTION

With the installation of large amounts of LV- and MV-connected renewable generation, especially photovoltaics, wind turbines and biogas plants, voltage rise has become a more significant planning parameter than voltage drop [1,2]. Constraining voltage rise is challenging for a number of reasons. If renewable distributed energy (DER) is the primary cause of voltage rise, it is subject to significant changes based on time of day and season, and stochastic rapid changes due to shading and cloud cover. To maintain acceptable voltage levels from the primary substation to the most distant LV-connections and avoid wearing out tap-changers on primary substations, voltage rise at a given voltage level needs to be more constrained than voltage drop, for example 2% as opposed to 7%. Second, the maximum power flows due to DER are often much higher than maximum demand-only power flows, sometimes greater than three-fold.

A practical planning algorithm must evenly cover a wide range of driving parameters, and be adaptable to embrace the specific challenges of distribution companies in a wide variety of environments, ranging from dense urban to sparse rural, networks that are heavily demand dominated to networks that have significant amounts of DER. Enabling every possible feature in a planning algorithm for each scenario would needlessly compromise computation times. In fact, taking care of some technical parameters, for example the lifetime cost of losses and interruptions, may take care of other technical constraints. The algorithm [3] takes care of thermal constraints and optimal conductor sizing if motivated by the cost of losses and contingency rating, with, previous to this paper, a user-adjustable global variable to handle voltage constraints. This global variable has been automated, but is inadequate in dealing with heterogeneous networks where, for example, there may be a local voltage problem caused by an MV-connected field of photovoltaics. The global approach is overly conservative, as a local voltage problem may cause the entire network to be over-dimensioned. In short, dealing with voltage rise has necessitated a comprehensive upgrade of the algorithm and this paper shows how this has been achieved, but with methodology that is general in scope. There are many other research teams investigating distribution network planning with DER, e.g., [4], which explores uncertainty and reliability in expansion planning, and [5], which looks at the impact of control and automation on network planning.

A myriad of investigations and simulations are possible, but this paper will focus on general methodology, and specific simulations investigating the impact of loss costs, planning horizon, allowing of larger conductor cross-sections, and the pros and cons of heuristic planning rules vs. no rules in a distribution network planning algorithm.

METHODOLOGY

Fig. 1 illustrates the logic used to manage some of the main constraints in such a way as to not to unduly punish computation times. The treatment of voltage in the algorithm is decoupled in that every time the algorithm makes an otherwise cost-effective change (i.e., an improvement in the present value of the sum of investment, loss, operation and maintenance, and interruption costs), the full solution is checked for planning rule violations such as crossed lines. The underlying radial network is checked for normal operation voltage violation, and then violation during the worst contingencies only if normal operation voltages are within limits (or can be brought within limits by line section stiffening).

The parametrization of nodal data is handled by an interface that can couple time-series data to the algorithm, or operate more conservatively from fixed maximum and minimum active powers at every node (secondary substation), coincidence factors (1 is conservative) and loss times (related to maximum absolute demand at the node (negative demand implies generation dominates).

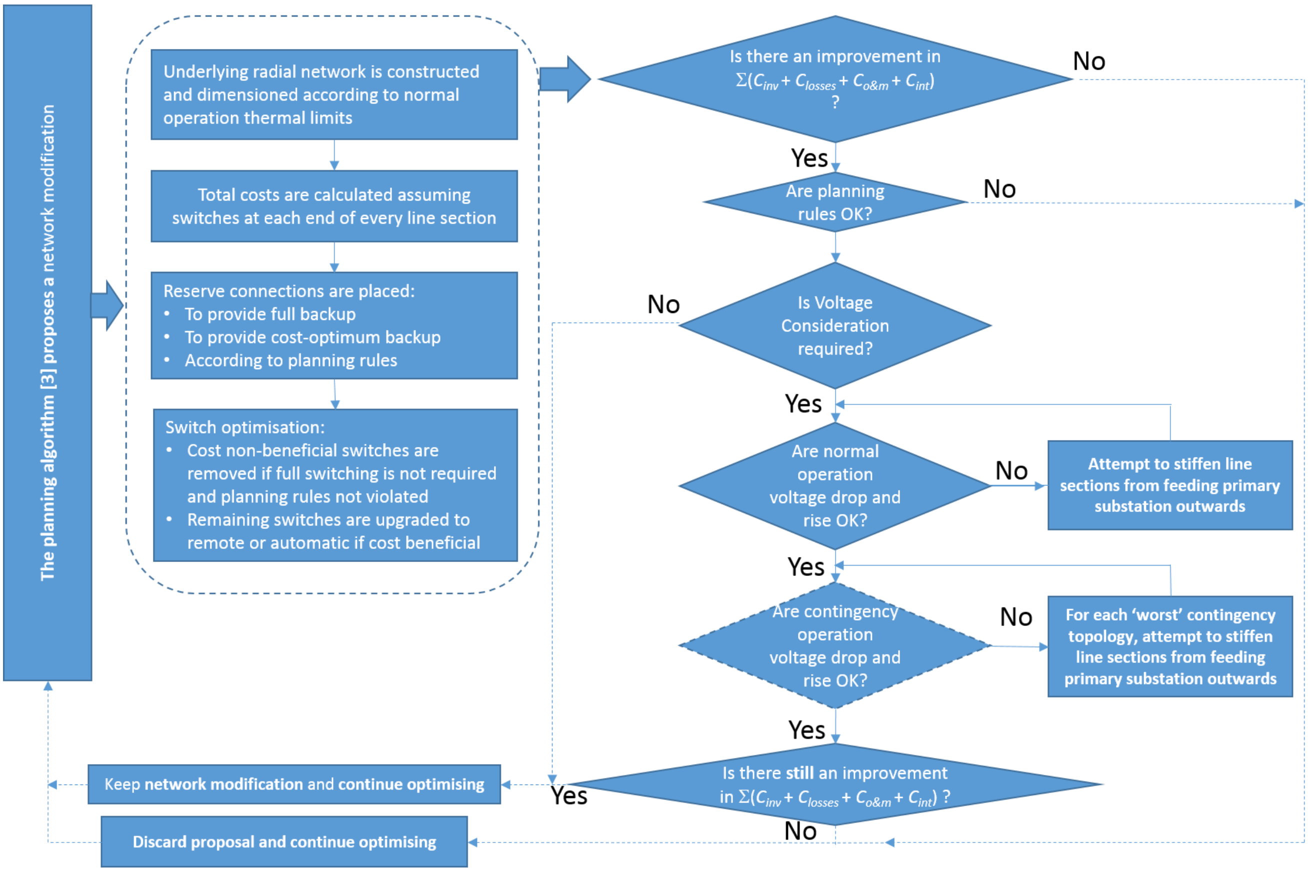

Figure 1 Flow chart indicating how planning rules and voltage constraints are explicitly treated in a distribution network planning algorithm

Backward sweep power flows based on a lower bound operating voltage are run for maximum demand, and minimum demand if distributed generation dominates anywhere in the network under consideration.

Planning rules, such as the number of distribution substations or amount of demand that can be left without backup on a spur feeder or between switches, are implicitly treated in the functions that remove redundant switches and apply reserve connections. The planning algorithm itself is branch exchange-based, but with a wide variety of functions that search for local suboptimalities and implement network improvements that require multiple simultaneous branch exchanges, and kicking functions that force the evolving solution out of globally suboptimal blind spots.

RESULTS

The medium voltage (MV) Greenfield network simulations shown in Figs. 2 to 6 are based on realistic load and generation data, and real geographic data from a region in Bavaria, however space does not allow all the nodal data to be given here, as there are 3 primary (HV/LV) substations and 230 secondary (MV/LV) substations, the majority (206) of which have distributed generation, where on average, peak generation exceeds peak demand (power, not energy) by a factor of 3.6. Some parameters are given in Table 1, noting the severe constraints on voltage. The network solutions are driven by interruption costs of 1.1 €/kW/fault and 11 €/kWh, and planning rules, which dictate that no more than 3 substations with demand or a maximum of 1 MW aggregate substation capacity are exposed to repair time by being on a spur or between switches on a trunk feeder.

Fig. 2 shows a solution where the review time (T_{review}) is only 5 years, investment costs are prioritised (loss costs are not considered) and reliability is taken care of by the above mentioned planning rules and interruption costs. The network is clearly constrained by voltage rise, with both the contingency ($V_{drop,max,cont}$) and normal ($V_{drop,max,norm}$) operations close to 4% and 2%, the stipulated limits. The costs given in the first column in Table 2 are 5 year costs, the present value of investments and interruptions. The second column is more suitable for comparison with the other simulations, as it gives 40 year costs for the same network (based on T_{review} = 5 years), including the cost of losses (and interruptions) over 40 years.

Table 1 Some constraints and parameters

V_{drop_normal}	7%	interest rate	3%/annum
$V_{drop\_contingency}$	10%	load growth	0.1%/annum
V_{rise_normal}	2%	$C_{inv,150mm^2 cable}$	70 €/m
$V_{rise\_contingency}$	4%	$C_{inv,300mm^2 cable}$	80 €/m

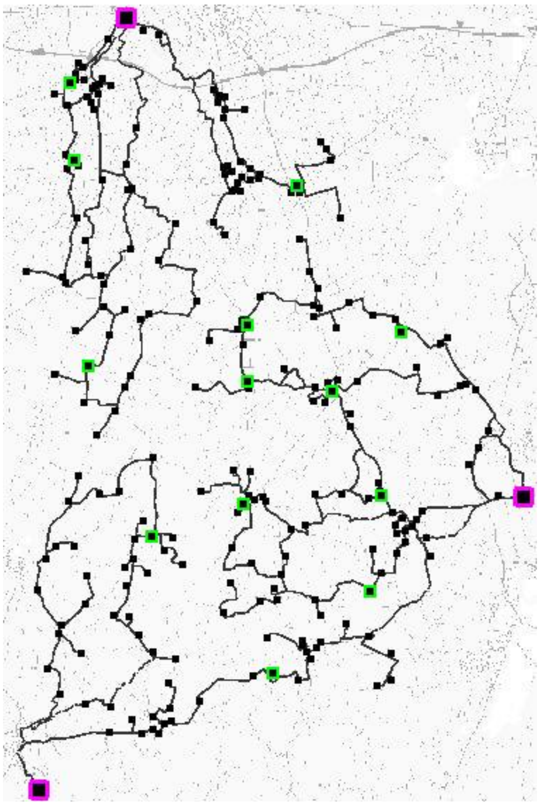

Figure 2 Distribution network solution for T_{review} = 5 years, utilising only small conductor size, Al 150 mm^2, and no loss costing. The green squares indicate the normally open points.

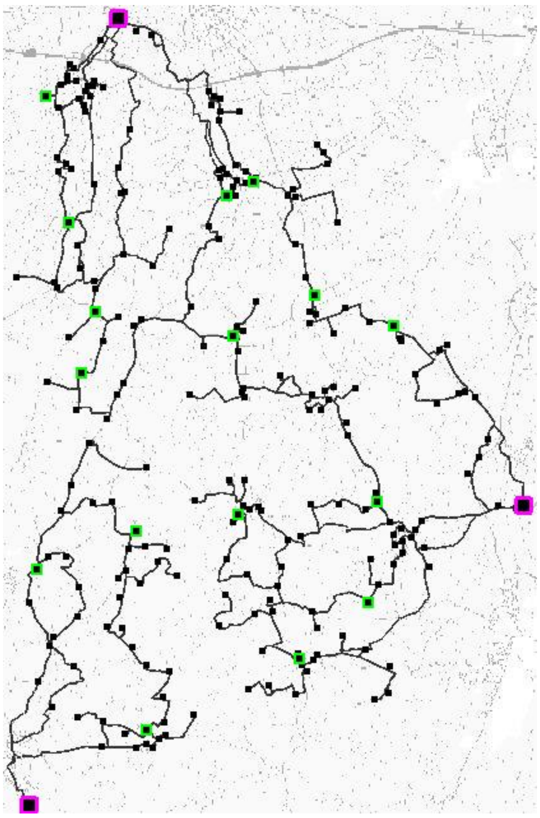

Figure 3 T_{review} = 40 years, with loss and interruption costs considered. Only one cable size, Al 150 mm^2.

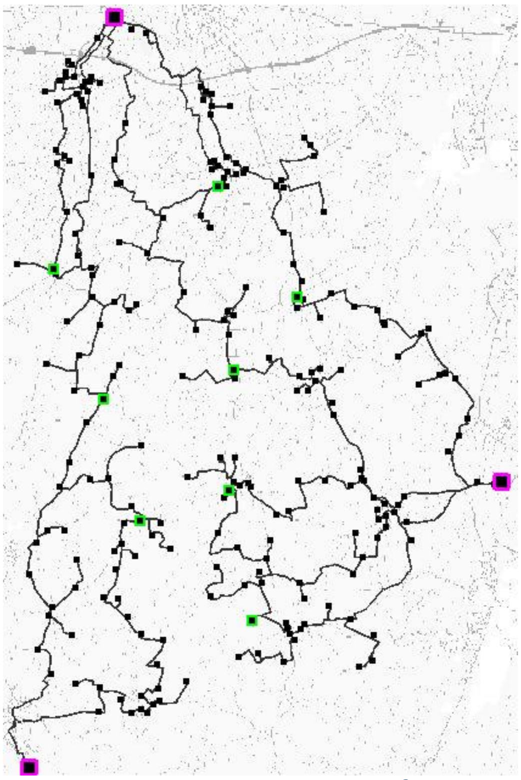

Figure 4 T_{review} = 40 years, and large 300 mm^2 conductors

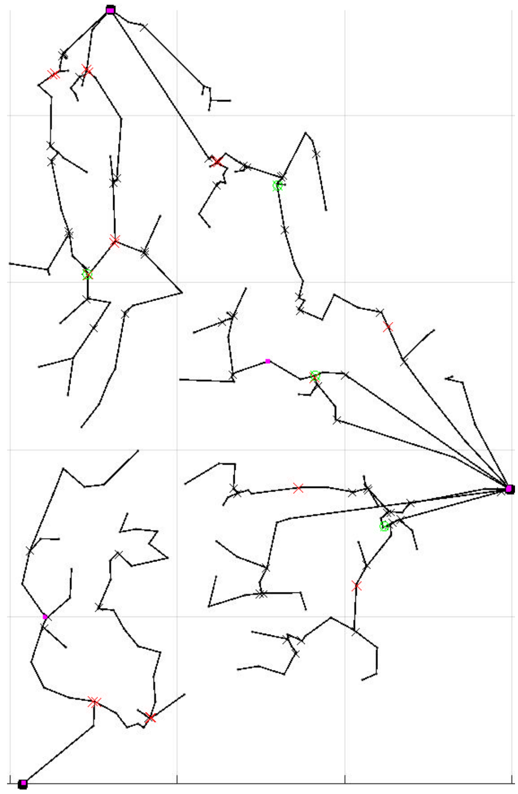

Figure 5 Relaxation of planning rules, 2 conductor sections, and remote switches and field circuit breakers allowed. T_{review} = 40 years (133km of 150mm^2 and 66 km of 300mm^2 cable) - topological view, showing position of manual switches (black crosses) and remote switches (red crosses). Normally open points are indicated by green circles.

Table 2 Summary of solutions, costs and components (Yellow highlights indicates final results)

	Fig. 2: T_{review} = 5 years, utilising only small conductor, and no lost costing	Fig. 2 solution based on T_{review} = 5 years, but including loss and interruption costs over 40 years	Fig. 3: T_{review} = 40 years, with loss and interruption costs considered and only small conductor allowed.	Fig. 4: T_{review} = 40 years, and large 300 mm2 conductors	Fig. 5: Relaxation of planning rules, 2 conductor sections allowed, remote switches and field circuit breakers allowed	Fig. 6: Full backup with 2 conduc-tor sections
C_{inv} (k€)	23 829	23 828	24 162	21 184	19 878	24 085
$C_{interruption}$ (k€)	214	1 082	903	1 130	1 298	612
C_{losses} (k€)	0	1 641	1 599	1 244	1 829	1 805
C_{total} (k€)	**24 043**	**26 552**	**26 664**	**23 558**	**23 006**	**26 502**
$V_{rise,max,norm}$ (%)	1.97	Exceeded limit	1.8	1.2	2.3	2.4
$V_{rise,max,cont}$ (%)	3.96	Exceeded limit	3.7	3.6	4.0	6.4
$V_{drop,max,norm}$ (%)	0.82	N/A	1.0	0.6	1.9	1.5
$V_{drop,max,cont}$ (%)	2.16	N/A	2.0	1.5	1.6	2.7
$LF_{max,norm}$ (%)	39.7	N/A	27.8	32.1	32.9	47.7
$LF_{max,cont}$ (%)	59.6	N/A	51.4	60.1	75.6	66.3
Manual switches	109	109	138	125	62	445
Remote switch master stations	0	0	0	0	12	21
Remote switches	0	0	0	0	20	29
Network circuit breaker master stations	0	0	0	0	2	0
Network circuit breakers	0	0	0	0	2	0

A general view of the simulation results and total costs in Table 2 indicates that geographically constrained underground cable networks have quite similar topologies, and it is clear, for underground cable networks, that investment costs are the main driver for total lifetime costs, even when the planning horizon is as long as 40 years. There is a reverse correlation, however, in the relationship of interruption costs with loss costs, Figs. 3 and 4, as using bigger conductor sections with lower losses, means fewer feeders are needed to supply the loads, which increases the number of customers interrupted due to a given fault.

The planning rules are relaxed for the network in Fig. 5, which leaves the network much more exposed to outages, with long spur feeders without backup. Whilst this may be a more globally optimal solution, it treats customers in different parts of the network unevenly, and regulation models may punish long outages for customers connected to substation that have no backup, implying waiting for repair time for restoration of supply after a line fault.

The final simulation, shown in Figs. 6 and 7, forces full backup to every secondary substation, even generation-only nodes, which obviously drives investment costs up when compared to the solution in Fig. 4, but provides a solution that is in some ways more robust and *fair* to all customers, and somewhat more able to cope with uncertainty in demand and generation forecasting in the time horizon of network primary components. Note, however, that the contingency voltage rise limit had to be relaxed to get this solution. Full backup, especially from adjacent primary substation areas, can be difficult (expensive) to achieve for secondary substations that do not lie between primary substations.

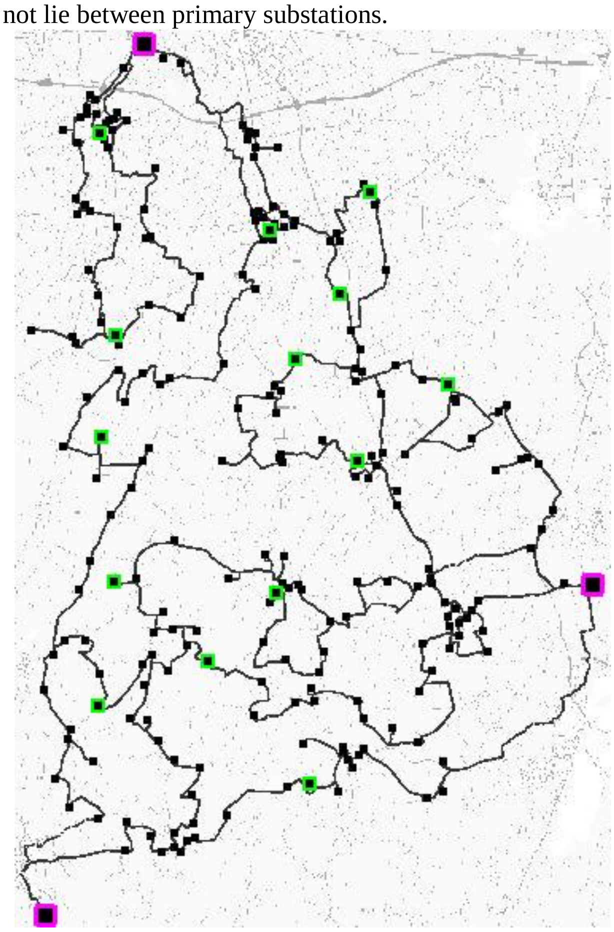

Figure 6 Full backup with both conductor choices - topographic

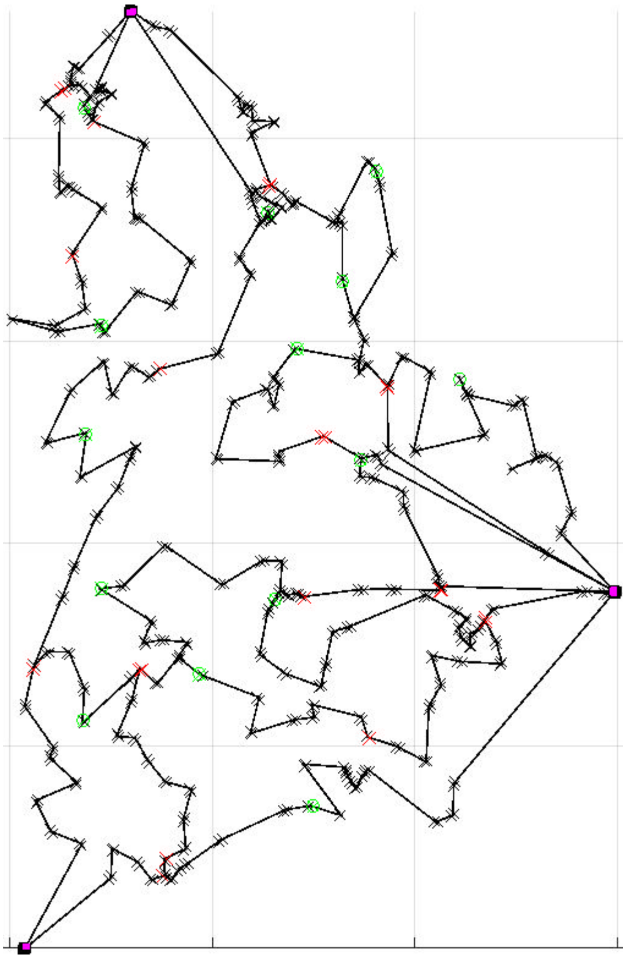

Figure 7 Topological depiction of solution shown in Fig. 6, showing position of manual switches (black crosses) and remote switches (red crosses). Normally open points are indicated by circles

DISCUSSION

Network plans in the real world are usually Brownfield, but Greenfield target scenarios were chosen to highlight the points under focus in this paper. Whilst the priorities of network planners may be to keep investment costs within annual budgets, provide reliability according to rules or regulation requirements, and not prioritize the cost of losses at all, the paper indicates that longer target horizons that take into account the societal cost of I^2R losses and interruption costs tends to produce networks that, viewed in terms of cradle to grave costs, are not much more expensive, but are more robust.

The quantification of interruption costs depends on the country and regulation models, and it is to be admitted that whilst in the Nordic countries, customer interruption costs are quantified for the various customer groups, not all countries do this, and planning rules, such as only allowing 1 MW of substation capacity or a maximum of 3 MV/LV substations on exposed spur feeders or between switches in the trunk network are also pragmatic, although do not in themselves cater for important customers.

The impact of loss costs is not as significant for underground cable as it is for overhead line networks, and the interest rate used also has a strong impact on the present day value of costs from the distant future. The contention is that full lifetime costs should be used in planning, not short 5-year time horizons. Planning is an inexact science, and it might be argued that a long planning horizon of 40 years is very hypothetical, but using a shorter review period will tend to yield weaker network solutions that are less able to cope with future load growth, which may well be in the form of distributed generation imposing high instantaneous reverse power flows and vehicle charging, going into a carbon-free power system future.

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