Distributed Marginal Price (DMP) Methodology Applied to the Value of Solar

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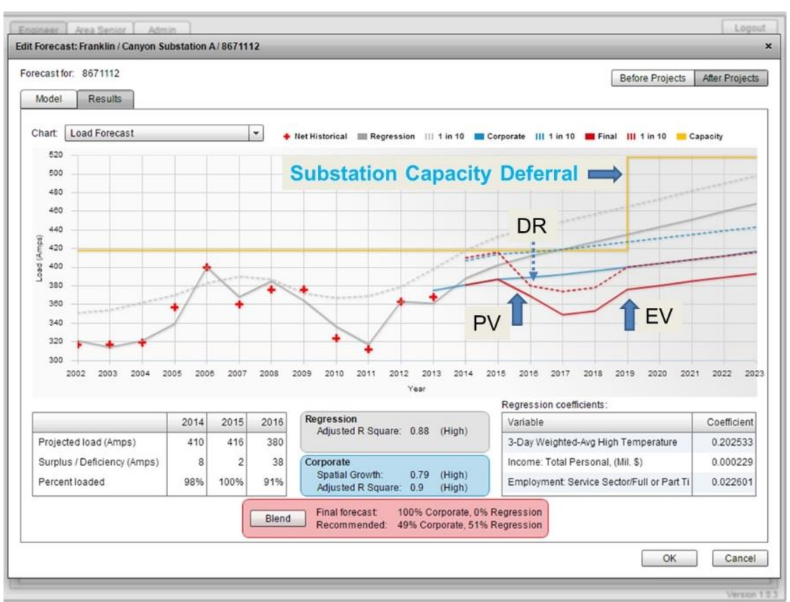
Introduction

The Distributed Marginal Price Methodology (DMP) specifically calculates the marginal cost saved or value generated from distributed energy resources (DERs). Regardless which utility business model one may advocate, the details and methods provided within the DMP framework are necessary to provide the empirical data required for any new utility business model. DMP methods align with and supplement traditional IRP methods and LMP derivations. The ultimate outcome of applying DMP methods is a mathematically-based least cost DER plan, whether those resources are investments by the utility or via third parties or customers. In addition, the DMP methodology produces marginal distribution cost values that are linked to specific DERs at specific locations and include **both** forward fixed and variable costs, incorporating both the grid and traditional supply drivers. DER operational dispatch costs or prices are essentially short-run DMPs (hourly or 5 minute) that can be bid-based in the same way that LMP prices are issued. These cost signals reflect the incremental resource cost for a specific DER at the specific node or location. And importantly, these costs or prices are based on granular utility costs derived via a mathematical optimization similar to that used to derive LMPs and 'system lambda' production marginal costs. This assures users that we have a fully specified least cost outcome across DERs, jointly, inclusive of grid and supply avoided costs, and for both short term and long term capacity. We simply include more granular grid costs and layer in power flow equations to ensure that reliability needs are made explicit.

DMP methods differ from Transactive Energy frameworks in that DMP methods ensure that the results have a utility cost foundation prior to their use within animated market contexts. If one does not first know the marginal distributed costs where DERs could be installed, then it is impossible to develop least cost planning outcomes. One objective of this process is to provide the framework that encourages DER providers to bid resources into these markets, to glean competitive efficiencies. However, the utility and regulators first need to know the avoided costs that can be achieved by a DER, at a location. This is the value below which market animation should be enabled. Ignoring these distributed marginal or avoided costs risks either 1) overpayment for DERs, or worse 2) gaming of markets. Our goal here is to provide more detail and insight into the necessary foundations for deriving these important marginal cost values.

In almost all cases, to date, an actual DMP price has not been published, or used, in a regulatory approved TOU-type rate. And in fact, a utility does need to change rate design or employ TOU rates to achieve a robust DER-enabled grid. Rather, DMP methods used to date calculate the total dollar cost savings (avoided costs) from DERs, and this is referred to as the Distributed Marginal Cost (DMC). So, a DMC cost is a total sum of dollars saved, for (1) variable energy costs, (2) variable grid costs, (3) the long-term forward capacity savings, and (4) forward grid capacity deferral savings (see insert). A DMP value is a unit cost or price, which may or may not be published (e.g., $/kVAR, $/kWh). The main reason that people often use the DMP acronym (vs. DMC) is because DMP concepts have intuitive parallels to



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LMP derivations. So, we typically use the DMP acronym generically to refer to the complete family of DER valuation methods, of which the total dollars saved (DMC) is a core part. The DMP methodology uses true mathematical optimization across several energy cost components, to obtain least cost outcomes and insights. LMPs are derived from supply costs included within a network power flow model with transmission constraints. DMPs are derived from distribution costs added to these supply costs, and then modeled within radial power flow models, to obtain least cost distribution level outcomes and insights. DMP methods use the LMP as an input, so that the complete value of energy and transmission to each substation is included with the DMP analysis, implicitly. So, in planning, DMP least cost optimizations can be couched as “mini-IRP” models, circuit by circuit, which complement the analysis already performed by LMP as well as traditional IRP analysis, and which incorporate the richness and detail of what already exists in an LMP. However, unlike an LMP which usually is considered as a price or value that exists only in near real time, or next day operational contexts, the DMP and DMC calculations are performed over future, forecasted years, and over the expected life of DER measures (e.g., 20 years for PV). This makes a DMP-based DER strategy imperative for utilities seeking to deploy and manage the lowest-cost portfolio of assets on the grid edge.

There are four general categories or quadrants of avoided costs within the set of DMPs that relate to Supply vs. Grid and Fixed vs. Variable (fixed costs are annual, and variable costs are hourly or sub-hourly). Fixed Supply costs are tracked as $ per kW per year, and Variable Supply costs are in terms of $ per kWh. These are familiar. However, because we calculate the cost to serve from the bottoms up, we now have enabled the derivation of unique customer specific capacity valuation and energy costs. These more granular and accurate cost to serve results can be used for more intelligent targeting of demand response, energy efficiency, solar, storage or other resources. This improves the overall cost effectiveness of DER portfolios, and enables a richer set of policy levers than traditional average rebates or overly-general approaches. Even if incentives remain a single averaged value, improved outcomes arise simply due to a more intelligent target marketing strategy where more funds are targeted to desired locations, streets or homes.

Perhaps the most important value derived from DERs, such as solar, is the DERs ability to avoid not only future energy and capacity costs, but also future grid capacity needs. The main purpose of Integral Analytics’ (IA) LoadSEER software platform is the derivation of defensible grid capacity forecasts such that planners are able to assess capacity needs and deferral opportunities as well as DER grid risks. Use of DMPs is the only way to determine forward-looking transport tenders for capacity and is a necessary and fundamental first step toward understanding any nuance related to a DSO, a DER rebate, a net metering subsidy or new utility business models where significant DER penetrations are expected.

Prior to the widespread emergence of solar, it was acceptable for the utility to have a single 20-year load forecast for a city. But as solar arises at the grid’s edge, the Distribution Planner must become a central player in the IRP process because these distributed generation resources disrupt the traditional planning process, can pose a serious risk to energy delivery and add significant additional costs. The only way for this Distribution Planner to preserve reliability is to use a more sophisticated grid capacity forecasting and

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modeling application. Moreover, since the Distribution Planner's world is measured in kVA, not just kWh, inclusion is essential for previously ignored issues such as voltage, reactive power and protection. The DMP methodology does this. It uniquely combines econometric least cost planning principles directly within radial power flow engineering, while at the same time implicitly embedding traditional IRP assumptions and LMP values.

Distributed Marginal Cost and Price Concepts

The calculated DMC dollar values, in total or in component parts, represent the marginal cost that could be avoided at a specific location for a specific DER at a specific location. A least cost focus suggests that a utility is theoretically justified in paying up to this amount for the DER at that place, and should presumably merit retaining a portion of the value for securing resources below the DMC. However, a utility may animate a market by enabling third party bids for this DER at that location, and the lowest-priced bidder (which is also below the DMP) is awarded the project. This market animation ensures the continued realization of least cost outcomes.

Importantly, it also protects ratepayers and customers from over-paying for DER resources. Without knowing the cost threshold of the DMP, two parties might conduct a bi-lateral exchange which exceeds the marginal DMC cost, or worse, causes increased costs due to unmanaged over-voltage or other energy delivery risks. Several Transactive Energy advocates overlook this issue, arguing for purely free markets, without regulatory oversight.

Optimal Least Cost DER Mix by Service Transformer

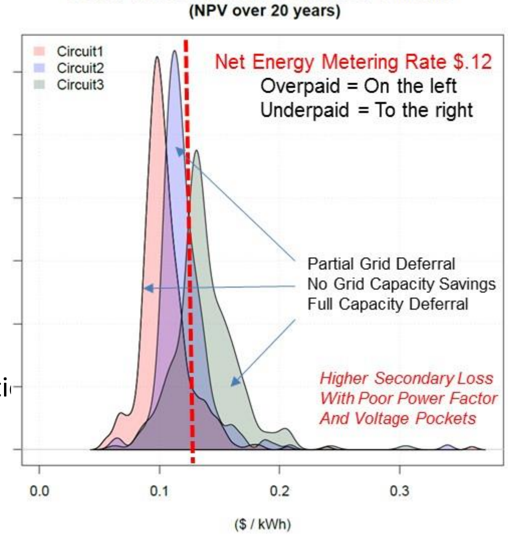
(Scenario = Low Storage Cost, Modest PV Cost, Low EE)

The DMC cost value provides the desired marginal cost metric that directs DER investment in the right place, in the right amount, therein revealing the ideal distribution resource plan. Of course, customers and vendors will behave in unpredictable ways, and pursue DERs for not just financial reasons. Any planning and management approach must overlay the optimal forward portfolio mix based on the current portfolio status. Therefore, this process of calculating new and updated DMC cost signals should be a dynamic one, essentially driving **continuous annual commissioning of the grid edge, updated with evolving DER**.

And because kWh and kVAR are so closely intertwined in energy delivery, forward tenders for energy may not be easily transacted without careful and simultaneous consideration of the forward costs for energy delivery or transport. Whether issued and managed by a DSO, the utility or a clearinghouse, market bids for DERs can be used to provide competitive pressure and lower these same costs. This holistic approach is the only way to completely value the benefits, costs, and market aspects of adding DERs to the grid, by location.

Let's start with a simple example which compares a net metering solar credit (12 cents per kWh) with a DMC-specific comparison. Here, we use the term DMC since

Density Plots comparing the $ / kWh for 3 Circuits
(NPV over 20 years)



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we will only examine the total dollar cost savings. We are not reporting the costs as $/kVAR or $/kVA, the more detailed DMP metrics, though this detail is included in the underlying quantifications. Here, for simplicity, we sum up total dollar savings (total $$ DMC), then divide by total kWh saved, for direct comparison to the 12 cent credit.

To compare directly with this metric of 12 cents per kWh for solar net metering, we will create a single $ per kWh metric, but we will also quantify all $$ DMC cost savings across *both* grid and supply. First, we sum up all the DMC $$ saved, *by customer*, for 3 example circuits of varying capacity needs (Full, Partial and None). So, this amounts to around 9,000 homes. The 3 probability density functions (at right) show 3 distributions, one for each of the ~3,000 customers on a circuit. The pink distribution (left-most) has zero forward grid cost savings, and has an average solar energy savings of about 10 cents/kWh which is already lower than the 12 cents currently being paid. The light green distribution provides value above the 12 cent net metering rate, but includes additional grid cost savings. The comparison is not quite this clean, as there are actually some modest variable grid costs included in the left-side pink distribution (e.g., power factor, secondary losses, voltage), but these generally are not wide spread, for these circuits. We do observe some pockets of higher variable grid costs on the far right side of the distribution's X axis, but not many. The exact percentiles of comparative costs associated with these same pink, blue and green probability distributions is shown empirically in the table below.

For each of the Circuits (Full, Partial, No Grid Savings), we can view the actual cost savings (to the utility) from PV placed at each house. In this case, there is more variability due to energy savings and the coincidence of the customer's loadshape to the system. But, this is not always the case. There are many other circuits where the grid cost variability can be higher than the energy variability, particularly where the circuit serves homogenous home types and inhabitants, is rural, serves agricultural loads, and other customer types.

Value of Solar Distributions

Cost to Serve savings calculated for thousands of customers across three different circuits of varying capacity need (forward deferral value).

	Distribution CIRCUIT Capacity Deferral		
Percentile	None	Partial	Full
1st	$ 0.060	$ 0.066	$ 0.082
5th	$ 0.076	$ 0.096	$ 0.100
20th	$ 0.092	$ 0.107	$ 0.123
Average	$ 0.101	$ 0.116	$ 0.134
80th	$ 0.115	$ 0.130	$ 0.157
95th	$ 0.142	$ 0.157	$ 0.187
99th	$ 0.181	$ 0.202	$ 0.235

Overpaid

Underpaid

20 Year NPV value, 7% discount rate, 3% inflation
~ 10,000 customers, 30 yrs hourly weather, 4p system peak
Partial case = Capacity need Yr 8, but afternoon KW peaks
Full case = Capacity need Yr 2, later evening KW peaks

Base Net Metering Value = 6 cents	1st Percentile Energy, Zero Grid Savings
Vendor's Grid Bounty = 2.2 cents	Full Deferral (on 1st row) minus No Grid Savings
Shared Energy Bounty = 12.1 cents	99th Pct minus 1st (due to loadshape/coincidence)

Given this granularity, what we want to know is how well does this 12 cent net metering credit value reflect the actual "cost to serve" savings from solar, where the savings to the utility are holistically analyzed across 1) energy, 2) forward energy capacity, 3) variable grid costs (voltage, power factor, etc.), and 4) forward grid capacity (None, Partial, Full).

In the table, the net metering subsidy is easy to see. All customers yield at least 6 cents of utility cost savings (see above $$DMC, None, 1st percentile). If that customer at 6 cents were to be relocated to the Full Deferral circuit, the value jumps to 8.2 cents, reflecting a Locational Bounty of 2.2 cents that a third party provider arguably deserves for targeting and promoting PV on desired circuits. No rate

Balanced Policy Driving Optimal Outcomes

Empirically, a reasonable policy might suggest the following:

Customer Incentive	$.092 (Base @ 20th pctile)
Vendor Bounty	$.02 to $.05 for right circuit $.001 to $.143, right house *$.143 = .235 (99th) - .092 Base*
Utility Earnings	15% of total DMC $$ saved

Note: Locational vendor bounties can be masked by grouping customers into Percentile Bins and/or simply identifying the Top Half or Top X% highest value customer targets.

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reform is needed to issue a locational incentive to a third party. And it does not discriminate across customers, as the customers' rates remain unchanged.

Though not universally true, this wide variability in customer types and loadshapes, for these 3 circuits, shows a larger range of energy cost savings than is typical. But we intentionally picked circuits with this wide range, to highlight cases where poorer power factor and longer secondary lines reveal wider probability distribution tails than normally occur. Generally, the variability in the cost savings is based on numerous factors including loadshapes, coincidence with peak, shifts in circuit non-coincident peak over time, power factor, and line losses. And this cost variability in the vertical columns reflects a 'shared energy' value. We use this 'shared energy' designation in light of the fact that some of what costs can be saved are controllable by the customer (e.g., power factor, natural load shape, circuit/system coincidence). Some are not (e.g. location, voltage, losses).

Hence, some of this 12.1 cent difference across customers (in the None column) should arguably go to the customer and some should be added to the vendor's Locational Bounty to incent third parties to target the higher value customers. Finally, some portion of the savings should be provided to the utility to motivate their animation of markets in this way. Historically, 10% to 20% shared savings earnings mechanisms were used to motivate utility support of energy efficiency. Emerging DERs are no different. DERs cause lost margin and lost earnings, which must be recouped in some way, if utility interest is desired. And, given the critical role that Distribution Planners and Operators play on the DER stage, utility participation is arguably necessary, whether or not one advocates for DSOs, a clearinghouse, or direct utility enablement.

Re-Optimizing The12 Cent Credit

To remove locational discrimination, and match 12 cents:

Customer Incentive	\$.092 (Base @ 20th pctile)
Vendor Bounty	\$.056 for Top Customers locations/ right homes
	\$.056 = .157 (80th) - .101 (50th)

Differentiation of Incentives by Location:
Where incentives and rates are historically based on average costs, it is reasonable to avoid differentiated incentives. Where competitive substitutes exist (PV), marginal costs must be used/ differentiated. Moreover, ISOs differentiate by location now via use of nodal LMPs.

The key point here is that fully enumerated DER costs and benefits need to be quantified at a more granular level before any policy decision regarding customer incentives, utility earnings or vendor bounties takes place. Without knowing the customer's cost to serve, and each DER savings results, prudent policy decisions, and the market structures they are to inform, are undereducated. Historically, regulators and utilities did not need to know customer-specific costs to serve. There were few, or no, substitutes to regulated energy. Today, utilities face imminent competitive threat from DERs. It is not difficult to see that least cost planning principles of the coming years fundamentally requires a more granular marginal cost metric like that provided by DMPs. Mathematically, we have grounded the DMP framework explicitly on the marginal cost to serve at the location, and as such, it fully adheres to least cost planning principles. Moreover, the DMP framework supplements existing IRP and LMP frameworks, such that no replication or replacement is required. The complementarity of traditional IRP planning and DMP granular optimization analysis is shown in the Appendix for those interested in the more detailed information flows and IRP linkages.

In summary, traditional net metering credits are essentially historical views of costs based on averages and ignore future cost concerns as well as how the costs change locationally. In the same way that IRPs are forward looking, so too should DER incentive policy be forward looking. DMP methods enable this. And policy decisions become much easier, and far more defensible, when stakeholders incorporate these cost-to-serve details. We have shown that DER market animation should not fund DERs at prices higher

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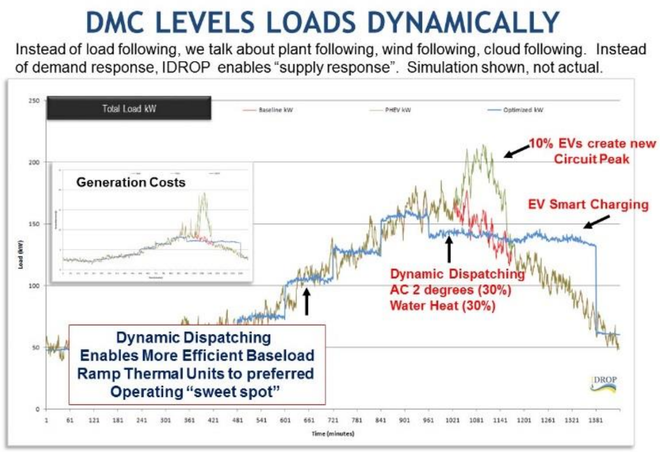
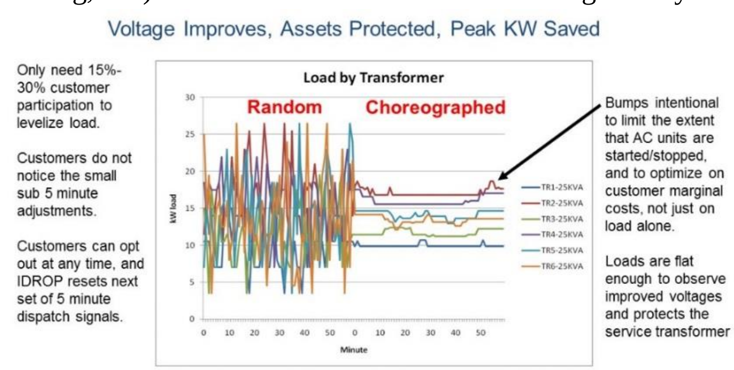
than the DMC maximum marginal cost (in total), but vendors or utilities might bid for DERs under this DMP marginal cost threshold. And finally, we see that a simple cost enumeration example highlights the ills associated with typical net metering credits.

DERs Changing the Landscape: Linking Planning To Operations

In the foregoing discussion, we observed that one can blend cost based analytics with market based animation of bids. Utilities and regulators are explicitly made aware of the true costs that underlie policy decisions, and can use this information to optimally design regulatory policy and utility earnings mechanisms. We are reluctant to prescribe specific utility earnings mechanisms as DMP methods can be employed in any of the proposed policies. The only case where DMP methods are not necessary is one where a regulator or utility does not care about cost-effectiveness, though this is a rare event. So, we are steadfast in our focus on the necessary accuracy and granularity that is required to quantify both variable and forward fixed costs (grid and supply, jointly) which can be used to inform such policy. The old days of averaged cost analysis cannot be successfully employed within the emerging context of DERs expressly because DERs often cause two-way flows of power and unique grid risks and opportunities. Concerns with grid reliability are also complicated by concerns with economic business models. DERs generally continue to erode utility earnings, defy the monopolistic foundations of traditional regulatory oversight, and provide attractive opportunities for new, near real-time balancing of the supply and demand. Many of our software-orchestrated DER dispatch projects (run through our IDROP application) have demonstrated this value and appeal. In fact, the virtual storage capabilities inherent within water heaters, building automation systems, VFDs, ceramic heating bricks, ice storage and a couple degrees of HVAC control over demand highlights this new era. Despite the current hopes surrounding physical storage, software-scripted virtual storage may be the least cost price-setter for intra-hour mitigation of solar or wind intermittency, or even intra-day (e.g., ceramic heating bricks, ice cooling, etc.). Customers that are not home during the day are the likely primary source of daylight intermittency solutions and will be the price setter intra-hour during daylight hours whereas physical storage batteries that most cost-effectively hold power for nighttime use will win the long term market proposition for converting solar energy to use during the night. These aspects of what type of DERs play key roles at what hours is currently an under-appreciated aspect of long term least cost planning. And this is where IA's DMP least cost methodological framework becomes more important. Its core function matches the production





Six transformers, 30 homes, displaying normal volatility in load prior to IA vs. after optimizations are operational.

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shape from a DER based on its attributes with customer level load shapes and location within the context of weather, economics and powerflow constraints. It reveals optimal long term strategies for resource subsidization across varied contexts in a more intelligent and rational manner, based on marginal costs.

Cost-Based Methods versus Market Based Valuation

Historically, the argument of cost-based versus market-based policies has always existed. Transactive Energy advocates tend to gird their philosophy in the efficiency of markets while state-based regulators tend to favor cost-based methods. We all recognize the risks and consequences of purely market-based philosophies (e.g., Enron, others, 2000) where markets were largely unchecked. And we all recall the original reason and rationales for the creation of ISOs to mitigate such gaming. Unchecked, Enron-style market gaming will occur on the demand side in the same way that supply-based market gaming occurred via withholding of supply in years gone by. In the absence of governing structure, an unscrupulous participant will,, secure sufficient control of 10% to 15% of demand in a region, where pre-cooling of homes, pre-charging of EVs, or other such demand control could likely influence prices. They might even double dip DR incentives in the afternoons. They will be savvy enough to limit their gaming below the radar screen of being obvious. Only a couple things will be able to mitigate such exploitation. Utilities will have enough direct control over loads via their own load control, or regulators will have adopted a DMP-type methodology to identify and mitigate such gaming.

In all cases, regulatory oversight is necessary. Proposals which allow free-wheeling bi-lateral contracts, such as those exhibited in the late 1990s, without regulatory oversight, are likely to meet with similar market inefficiencies, at best, and grid jeopardy, at worst. The advancement of physical and virtual storage mitigates such risks, but only if the ownership of these resources is either regulated via utility ownership of similar resources at equivalent scale, or the regulatory oversight of the clearinghouse mechanisms at play, or both. The DMP marginal cost methodology provides exactly this kind of metric under which regulatory oversight is possible.

Within IA's software, we always strive to evaluate both cost-based and market-based valuations. Our original demand-side program management application, DSMore, has provided direct comparisons for both, for years. As market prices boom and bust, DSMore has allowed utilities to assess the option value risks associated with multiple types of forward price, or avoided cost, scenarios. Moreover, our software methods enable the direct calculation of the risks and option values associated with DER technologies, whether traditional energy efficiency measures or newer distributed generation resources. Cost-based methods are not always complete, and market-based methods are often misleading for long term decisions. Neither is right or wrong. They both inform future decisions, and when we obtain comparable valuations from each, confidence increases. When we don't, at least we know where the risk lies. This is only way to plan and determine least cost long term outcomes. And with DER adoption uncertainty emerging in all markets at various places, both with solar and EVs, one must incorporate the risk assessment and benefit opportunities arising from both approaches. A wise man once said, "All forecasts are wrong". We only gain confidence when our software enables the analysis of multiple scenarios, including worst case, and this is an underlying principle of IA's software, many years running. Ironically, the higher the uncertainty surrounding DER adoption, the higher the option value of other DERs become, due to the risk mitigation opportunity. Demand response will necessarily evolve toward demand arbitraging, and, as a result, the more option value will be afforded flexible physical storage. And the more option value will accrue to inertial demand, such as, ice storage, water heating and a couple of degrees of HVAC (or many degrees of HVAC for customers not at home during the day). These

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resources will become price setters, and vendors and utilities that secure this participation early, and maintain it, will reap significant least cost opportunities as well as more robust reliability operations and grid management. In this case, customers will inevitably become energy price setters in opportunities that never existed before within mostly monopolistic contexts. The DMP marginal cost framework provides the foundational framework within which to quantify these value streams.

Misinterpretations of DMP Methodology

Over the past couple of years, we have observed a couple of key misunderstandings related to what the DMP methodology contains. To some extent, these misunderstandings are due to the fact that DER valuation is an emerging paradigm shift, requiring the valuation of resources in a much more granular and dynamic fashion. Historically, when the utility was a franchised monopoly with no competitive substitutes, it was sufficient to conduct analyses at a high, aggregate level. Average cost regulation was well-suited to this task. Going forward, the action is now happening at the edge of the grid, with many varied contexts, and we must directly include the impacts identified in power flow engineering in order to constantly rebalance the evolving mix of assets and attributes, consumption and production. We must force together two worlds (reliability and economics) into a single framework. This was achieved in the past for the transmission network power flows (e.g., ISO LMPs), and now it must be extended to the premise with the use of radial power flow model integration (a DMP, which is the LMP plus many D components). In New York, this is cast as LMP + D. But D has both variable and fixed components which importantly interact with the LMP, so it is misleading to think of these as separate concerns. They interact.

The DMP starts with the use of the LMP. The LMP value is always the base number upon which the DMP is built. They are not separated. All else being equal, the DMP rises and falls with the LMP, and so there is no separate consideration of LMP from D. This first step is intentional, as we strive to appropriately tie the dynamics occurring above the substation with the marginal costs which occur below the substation bus. This has caused some confusion in the past where some misperceive that the DMP and the LMP are to be added together. Below the substation bus, the LMP changes with changes in the DMP. The DMP adds Distribution components (e.g., power factor, specific locational losses, specific voltages at circuit sections). So, LMP is a base component of the DMP, but it gets adjusted and is no longer the same as the LMP we observe in the substation and cleared in ISO markets.

This is why DMP methods do not replace LMP methods. In long-run calculations the DMP supplements IRP planning and is applied sequentially by substation to complement the existing IRP planning process. Reduction in grid edge demands (which also have their own supply components, albeit with dramatically different load*shape* impacts) affects system level supply at the higher level, and thus the LMP is altered. The DMP and LMP are “marriage partners” embraced in a “dynamic dance” which redefines future DER/bulk supply overall planning processes. They are not fully separable, in the same way that kWh and kVAh are not fully separable. This is how it should be, given that these dynamically intertwined and causal considerations of AC power delivery should never have been teased apart, during the 1990s when EE and DR advocates separated them, for convenience and simplicity in application of EE incentives. Traditional HVAC incentives which are solely kWh and kW based overlook the increased costs accruing from the HVAC industry’s pursuit of these incentives to the detriment of kVAR cost increases. Going forward, a holistic valuation methodology is necessary to avoid myopic policy incentives. The DMP framework achieves this end.

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The above discussion focuses on the variable cost components of the DMP methodology. With respect to forward capacity costs, the LMP itself is of less use to utilities and market stakeholders. If ISOs, or utilities, provided accurate forward LMPs for 20 years, inclusive of granular DER forecast scenarios by substation, all would be in good shape. But since this requires an accurate set of load*shape* forecasts (not just peaks, energy and minimum load forecasts) based on low, medium and high DER penetrations, planners must turn to a spatial forecasting tool which blends econometrics, spatial location and DER adoption (LoadSEER). Forward capacity (now both grid and supply) must be provided from the grid's edge upward toward the sub-transmission level. With these, utilities can develop forward forecasts of future congestion, future LMPs and future capacity needs. This process is the primary reason our flagship software application, LoadSEER, was developed. Its load forecasts are the necessary granular load*shape* estimates required for grid edge planning in the face of DERs which dramatically change the loads observed at the substation buses. Traditional econometric modeling and forecasting alone is not sufficient to identify changing load*shapes.*

Given this important nuance, the D component of an LMP + D conceptualization of what is desired actually has a D forward capacity component which informs, and changes, the forward estimation of future LMPs at that substation. As utility customers run granular LoadSEER (load*shape*) forecasts through a network power flow model (e.g., PowerWorld), not only are they now confident in the forward capacity needs for the substation, theyalso increased the accuracy of the variable LMP forecasts into the future. Future congestion is more apparent, as is the specific location, which dramatically improves transmission planning and optimal placement of utility-scale DERs above, or near, specific substations.

Without this granular estimation of how load*shapes* will change, utilities and, therefore, DER market participants are blind as to the forward risk or opportunity of DERs. Reasonable forward grid capacity markets can only be informed, and quantified in this manner, despite the potentially onerous "bottoms-up" derivation. Note that we are careful to reconcile load forecast error between the Corporate or macro-level top-down forecasts and the aggregation of the many bottoms-up LoadSEER forecasts, but this is a necessary condition for accurate forward grid capacity valuations and for specifying a defensible DMP value for forward markets.

The key point here is that the DMP and the LMP are intertwined, and thus coupled. This is desirable in our attempt to link Transmission with Distribution, holistically. Treating LMP as separate from D can lead to suboptimal policy directives, potentially. This is why we shy away from specifications such as LMP + D. This conceptualization has value at a high level, but also loses nuance and appeal as one begins to understand the need to loosely couple, or even directly couple, transmission planning with distribution planning, while at the same time carrying the cost of energy with you along the way. Holistic thinking is more challenging, but the gird is dynamically holistic by nature, and requires the nuanced understanding. The DMP methodology strives to maintain this holistic coupling across both grid and supply, for both short and long term fixed costs, and recognizes that $ per KVAR is really what lies at the core of utility costs, not kWh alone. And not kWh variable costs viewed separately from forward capacity market valuations. They are intertwined. The DMP framework accounts for this, explicitly.

Finally, we want to emphasize that the DMP methodology absolutely enables valuation of long run grid capacity and its necessary forward components, although some still misperceive the DMP methods as being only short term and only operationally focused. This is likely because many of our early micro-grid pilots optimized DER resources in 2 second to 5 minute to hourly intervals. However, we realized many years ago that the bulk of the financial consequences from new DERs lie with their capacity value derived over 20 year valuations. **Ultimately, both planning and operational needs must be served using the**

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same core comprehensive valuation methodology. As such, we spent considerable time and effort perfecting the science (and art) of long term local grid forecasting via our LoadSEER platform. Without a rock-solid granular grid forecasting tool, accurate to the acre level, and used and defended by the Distribution Planner, one cannot even begin to discuss economic least cost optimization of DERs. In contrast to traditional IRPs, the Distribution Planner is now the heart of the future planning risks and opportunities. If one does not have a dynamically-informed software platform that addresses their needs for addressing planning risks, economic least cost optimization cannot even be intelligently discussed. The enabled Distribution Planner is in the best position to know what is going to happen to their assigned circuits. They know when the Walmart store is going to be built, and they know on which street corner. They know the magnitude of the new manufacturing plant because they have been speaking with the company for the past two years. They know where the commuter rail can be located, and where it cannot. There is not a better local area forecaster than the Distribution Planner. A corporate-level economist will not know these things. So, LoadSEER is designed as a "crowd-sourced" forecasting platform. Sure, it includes sophisticated econometric models and GIS satellite imagery and analytics, but this statistical savvy is combined with the local planner's own knowledge within the LoadSEER software. It is the best way to ensure forecast accuracy at the granular level. Distribution Planners are the key conduit through whom any economic discussion is eventually blessed or rejected. Their use of LoadSEER to manage the planning process and manage DER portfolio capacity and interconnection impacts flows directly into the economic optimization DMP least cost analysis. As such, regulators and utilities should be wary of any solution that provides only one method or "single vector" for forecasting. All forecasts are wrong. Multiple forecasting methods provide increased insights and flexibility to triangulate upon the "truth." LoadSEER provides four separate forecasting methods to better find the true path.

Getting Granular: Details Matter

Generally, someone will use the DMP acronym when they wish to discuss a price per unit, usually within an ISO context. In non-ISO states, proponents of DMP methodologies are more interested in the use of a DMC (DMC denotes the Cost in Total Dollars) simply to ensure least cost planning outcomes across both grid and supply. There is no need to publish a per unit DMP price. The DMP and a DMC are closely related, and sometimes used interchangeable, but technically, DMPs are a per unit value ($ per kVAh) and DMCs are the Total Dollars of cost savings over X years. We tend to overuse the DMP term simply because it is a simple analog to the LMP, both of which are the "shadow" price from a formal optimization model (the system lambda). The LMP shadow price arises from being embedded inside a network power flow model. The DMP shadow price arises from being embedded inside a radial power flow model. Hence, they are similar notions conceptually. But just because an LMP carries an ISO context, this does not matter. IRPs conducted in non-ISO States are essentially also LMPs. And so, too, the DMP methods are not restricted to ISO States. Any State can use the DMP methods with success.

Distribution IRPs (e.g., DRP in CA, DSIP in NY) identify the *optimal* mix of micro resources, and operations (e.g., DR, PV, Storage, EE, volt/var) which deliver the least cost plan in the zone between the substation and its customers. States generally mandate that power shall be delivered at least cost, reliably.

DMCs do not *replace* IRPs or LMPs.

They are granular complements.

The DMP methods stay true to this foundational principle. Interestingly, DMPs and DMCs are intentionally developed within an IRP-type philosophy and framework in that the optimizations used to create DMCs are mathematically based on avoided costs, just like supply-

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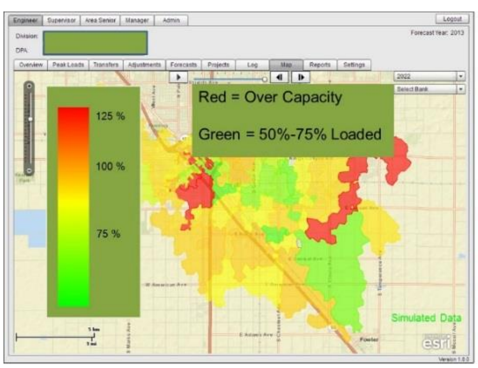
side IRPs are based on avoided costs for supply vs. DSM. Integral Analytics' optimization process identifies the least cost mix of resources on a circuit, based on the avoidable costs, but we incorporate both supply-side avoided costs and distribution-side avoided costs, including KVAR, power factor, voltage and other influences not found in supply-side IRPs where only KW and KWH are the focus. Because the Distribution grid holds many more complexities due to the increased granularity of the DERs and the loads, the optimization analysis is much more complicated than traditional IRP optimizations. Hence, several hurdles must be overcome, and the problem often is framed at different levels of granularity for different purposes. But, one cannot know the true marginal cost, on which to base policy decisions that are least cost focused, without some type of optimization methodology. And since future avoidable costs depend on both engineering modeling and very granular load information, one soon realizes that the first most important step is to embrace as much granularity as possible with respect to load forecasting analysis and batched power flow modeling. You can always aggregate granular results to higher level nodes for optimization analysis, but the converse is not true.

Note, too, that the Distribution IRP does not replace the supply-side IRP. In reality, there are a series of Distribution IRPs, one for each bank or bank group, or circuit, which complement the supply-side IRP focus, and generally reconcile their perspectives at the substation level, to avoid double counting or confounding supply side impacts. Where the supply-side IRP is focused from the "top down," the Distribution IRPs start from the "bottoms up". Because so many new micro resources are now emerging at the grid edge, this "bottoms up" view is necessary to ensure least cost planning and grid reliability. In many cases, DERs impact the lower line systems much more consequentially than the substations. Moreover, the insights that become clear in viewing the granular detail lead to 'hidden' benefits and strategies wholly unknown to "top down" proponents. Load leveling of otherwise volatile circuit loads can lead to not only KW reduction, but also improve voltage and reduced need for ancillary services. In some cases, short term forecasting error can be significantly reduced or removed via a bottoms-up focus vs. an ISO top-down ancillary service market pricing mechanism.

To Optimally Deploy and Manage DERs:

Need Granular:	*In Order To:*
Loads/Power Flow	Get granular nodal impacts
Cost Analysis	Plan/assess expected costs
Optimization	Calculate least cost
Market Signal	Drive customer response

LMP = "shadow price" (system lambda) from system network optimization
DMC = shadow price ($ cost on the margin) from circuit-level least cost optimization
DMP = per unit price ($ per kWh, kVAR, kVA) published for use in market animation



Financial valuation gains of 2X to 5X more cost savings on peak days beyond traditional DR strategies is entirely possible, but requires a bottoms-up construction. Creation of virtual storage using thermal inertia in water heaters, pool pumps and 1 to 2 degrees of HVAC yield significant "storage" buffers without paying the high price for physical equipment. Mitigation of renewable intermittency is enabled, where instead of forcing plants to do inefficient load following, we now talk of cloud following, wind following an even plant following. There are many new value streams and opportunities in this "bottoms up" view which complement the traditional "top down" IRP. But it clear that both are now necessary.

Bottom Line

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Distribution planners have traditionally focused first on reliability, and then on costs. Reliability was usually Job #1. Their load forecasts typically used simple models with only one temperature variable, and no econometric, time-series or geo-spatial locational detail. In most cases, loads were increased proportionately for all customers on a circuit, and not "aligned" to the nearest section of the circuit (except for cases of very large spot loads, or entirely new neighborhoods). Planners always knew this was important, but did not have quite enough funding or tools to make it happen, especially in a dynamically updating environment. The conceptual underpinnings of Distribution IRP analysis from the bottoms up did exist in some of the later chapters of Distribution Planner Handbooks, but was often dismissed as overly complex for current needs. The necessary PC processing capability was not available, and regulators were not clamoring for it, either. Neither were utilities set up for cross-silo cooperation and joint planning. Executive attention in the '90's and 2000's was generally focused mostly on the Supply side, M&A to reduce costs, or protecting the firm from supply side "gaming." This changed with the advancement of solar, AMI data, new innovations at the Grid Edge and a regulatory push toward more intelligent (aka, "resilient" in NY) Grid Planning. And so, the Distribution IRP framework now receives increasing attention and interest, as micro grid resources flourish and planners seek to *co-optimize* both grid and supply costs, across both short-term (variable) and long-term (capacity) considerations. This is what the Distributed Marginal Cost framework is designed to do.

Conceptually, though, DMPs are the LMP plus the D components that fit squarely within the same family as supply side "system lambdas" and traditional specifications of marginal costs. Generally we use the term DMC to reflect the cost times the load (or dollars of costs), whereas the DMP is typically shown on a $ per KW or per KVAh, or other unit basis. In either case, these values are nothing more than a granular set of marginal costs determined locally. The key point here is that the DMC or DMP is 1) very much analogous to a supply side LMP, 2) DMP calculations are grounded in a least cost planning framework, 3) DMPs are defined by mathematical optimization methods very much analogous to the methods used for traditional IRPs, and 4) the methodology yields a "global optimum", which tells us that this is the *best* optimal mix of DER resources for this circuit, or bank of circuits.

If customers respond perfectly rationally to these DMP prices signals, then we will obtain the optimal mix of DERs across the service territory which jointly determines the net least cost. If customers are not rationally economic actors (and they often do not make choices on economics alone), annual DMP updating derives new DMPs, given the new adoptions, and new cost signals guide future advances *toward* the ideal least cost optimal mix. This iterative process enables a reasonable balance between a purely least cost focus and a value-based animation of markets. We enable richer choice sets for customers while bounding the cost signal incentives within a range that prevents market gaming.

Inter-Relationships of IRP Planning and DMP Marginal Cost Calculation

The following chart depicts the key relationships and information flows required for derivation of DMC costs and optimal DMP least cost outcomes. Although the chart may at first be a bit overwhelming, the arrows highlight the key interfaces between use of averaged avoided costs (including GHG, forward supply capacity, networked transmission modeling) and the ways in which granular marginal cost and forecasting results feed back into this traditional planning process. The two worlds are loosely coupled at the interfaces enabling the DMP framework to richly complement existing IRP and ISO planning systems. The green arrow highlights the most difficult area of distributed marginal cost estimation and requires stochastic estimation methods beyond the scope here. These cost estimation methods require stochastic modeling and estimation, given the uncertainty of specific avoidable costs that lie between the circuit's exit from the substation and the service transformers. Finally, AMI data availability significantly

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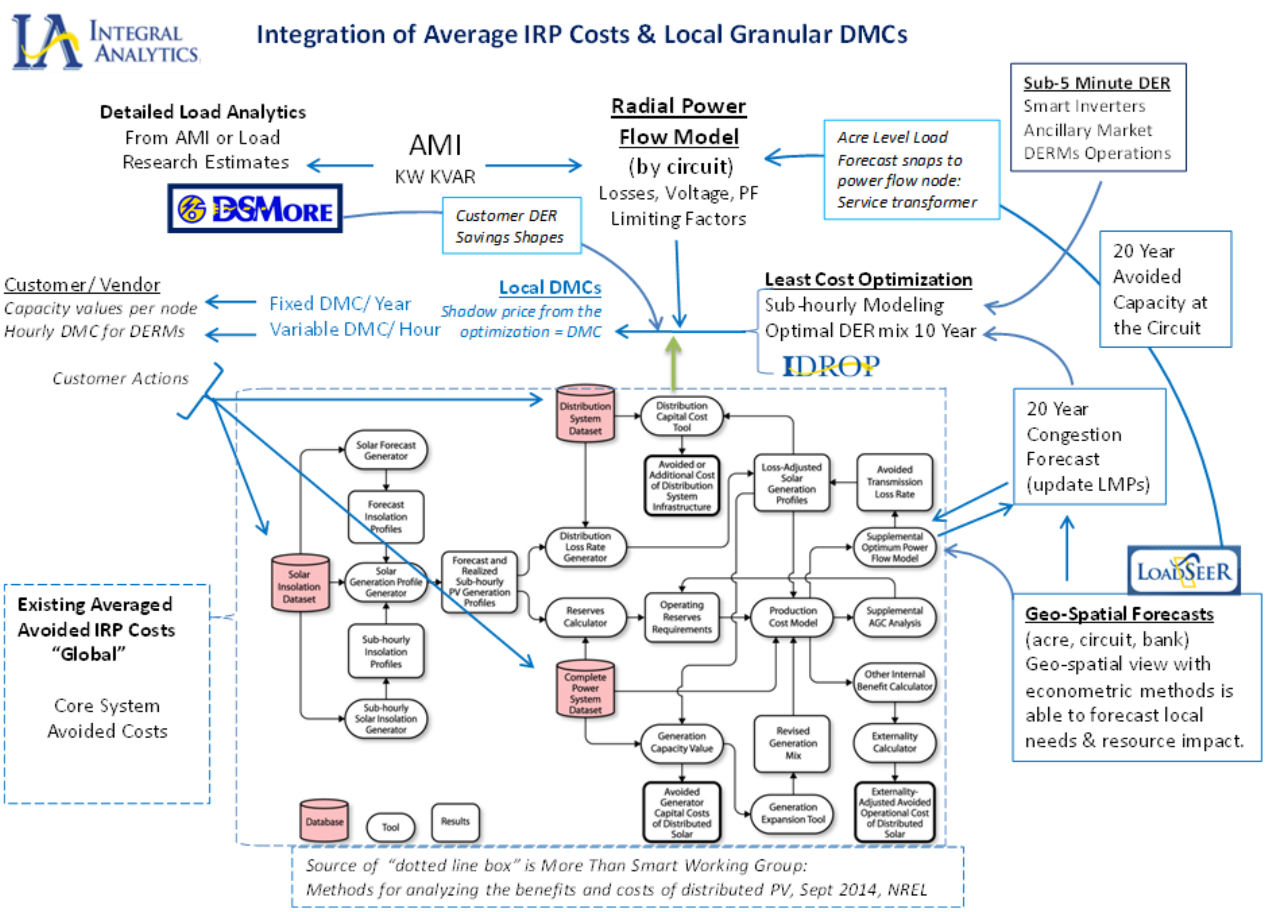
aids cost estimation (e.g., customer loadshapes, kVAR, voltage), but is not necessary. Reasonable customer class forecasts for these inputs can be leveraged, in the absence of AMI. Statistical estimation derived from existing load research meters, third party household and firmographic data, customer audit surveys and building simulation tools all aid in the estimation of customer loadshapes in the absence of AMI data. However, in the long run, accuracy at the grid's edge does matter, and increased situational awareness of locational voltage, power factor and grid assets is arguably a prudent step.



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