MERLIN

Modelling the Economic Reactions Linking Individual Networks

Milestone 3

2.04 Distribution Locational Marginal Pricing: A comparison of Canada and the UK

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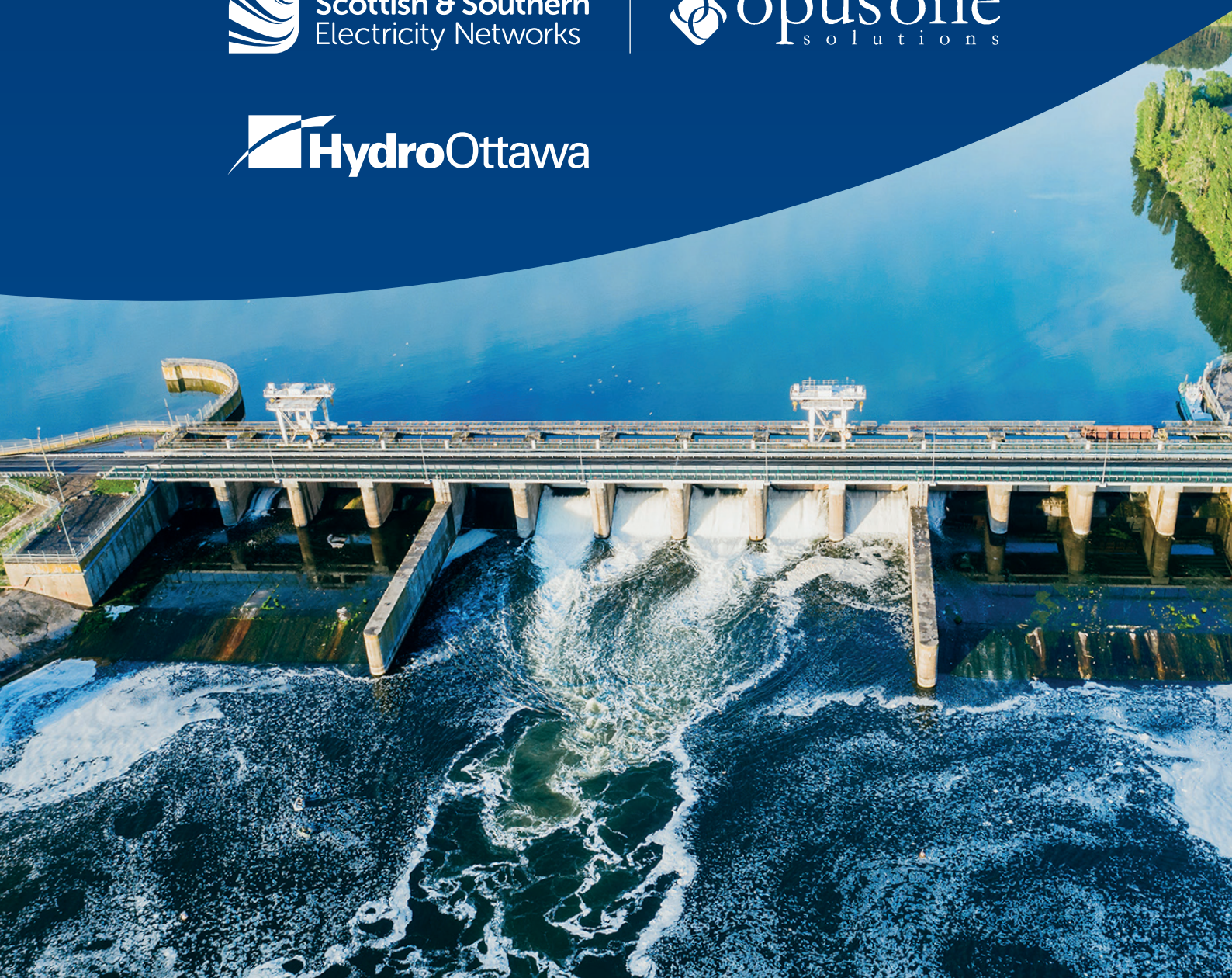

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Executive Summary

North American Independent System Operators (ISOs) are responsible for the coordination of generation and transmission across large areas in both the United States of America (USA) and Canada. ISOs have been operating spot energy auctions with locational marginal pricing (LMP) since 1998, and regulation and operating reserves markets with various designs for almost as long. The formal definition of a Locational Marginal Price (LMP) at some node *k* in the network is the marginal cost to the ISO of delivering an additional unit of energy to node *k*. Relatedly, we sometimes define the "transmission price" or "congestion cost" between two nodes *j* and *k* in the network as the difference in LMPs between the two nodes.

With the increase in number of Distributed Energy Resources (DERs), consumers can no longer be treated as the end of a supply chain that begins with bulk generation and ends with distribution to the meter. As such, there is an increase in the uptake of Transactive Energy Markets (TEM) which create location and time-specific prices that aid in animating DER participation in distribution systems. These markets create incentives for DER siting and operation that defer costlier, easier to strand investments such as large generating plants or wires and operate assets on the grid in ways that maximise their benefit to all consumers.

Unlike the Distribution Network Operators (DNOs) in the UK that only manage local power lines and substations, while energy suppliers sell the electricity that runs through the power lines, Local Distribution Companies (LDCs) in Canada are able to both manage the network and sell energy (at cost) to consumers. As such, transactive energy markets developed and managed by LDCs in North America are based on a pricing construct that is inclusive of energy pricing.

In creating TEMs in North America (these closely resemble flexibility markets in the UK), there are two principle approaches to pricing.

- Distribution Locational Marginal Price (DLMP): a granular, market measure of the utility's short run marginal cost (SRMC) at the specific time and location of the core electric product's use.
- Locational Marginal Price + Distribution Values (LMP+D): an average, administrative estimate of the "avoided cost" of the core electric product. For example, LMP (i.e. nodal, or wholesale value, of real energy) plus D (an estimate of average avoided distribution system costs i.e., difference between a "wires" and "non-wires" solution).

A hybrid construct may be to use DLMP for satisfying the supply-demand balance of the whole market, and use LMP+D to incentivise prosumers in supporting distribution grid constraint relief effort. This would build off of both the valuation approaches indicated above.

Objective of the Report

As part of the MERLIN project, Hydro Ottawa Limited (HOL) will be bringing forward and sharing learnings from its Independent Electricity System Operator (IESO) DLMP project (funded separately) and expanding this project to include examining and modelling the impact of TEMs on investment planning in Canada. HOL is an LDC that delivers electricity to, presently, more than 335,000 homes and businesses in the majority of Ottawa (Canada's National Capital), and the Village of Casselman, Canada, So, their role will facilitate trans-Atlantic sharing of the learnings and knowledge creation. Thus, the intent of this is report is to contribute to the knowledge dissemination component of the

MERLIN project in which a Canadian Local Distribution Company (LDC) and a UK Distribution Network Operator (DNO) exchange learnings from, respectively, a TEM and flexibility market trial.

This report is addressed for Milestone 3 of the MERLIN project and is one of other reports throughout the project. Milestone 3 is part of Phase 2 of 4 - the Modelling phase - and is to consist of information in the following chapters: : Chapter 1, an overview of DLMP with a jurisdictional overview; Chapter 2, an in-depth view of the DLMP methodology deployed as a part of HOL's TEM project; Chapter 3, results of this DLMP methodology on a synthetic network model that is popularly used for research and demonstration in the utility sector (the IEEE13 distribution network) as it also ensures that LDC and DNO network confidentiality is protected.

Additionally, the knowledge dissemination and transfer initiated by this report will be continued in demonstrations of project activities, results, and learnings for both HOL TEM and Scottish & Southern Electricity Networks (SSEN)'s flexibility market trial projects.

1 Introduction to Distribution Locational Marginal Pricing

1.1 Distribution Locational Marginal Pricing (DLMP)

Distribution networks are emerging as an increasingly important component of power system operations due to the deployment of distributed energy resources (DERs), which can be intermittent and whose operations are not necessarily visible to Independent System Operators (ISOs) or Distribution Network Operators (DNOs).

Presently, electricity in Ontario is referred to as "Postage Stamp" rates. Regardless of where the electricity is made and delivered to, aside from the time factor, the price is the same. Locational marginal pricing (LMP) is a way for wholesale electric energy prices to reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. LMP provides economically accurate signals at the wholesale energy market and has been utilised globally to facilitate competitive markets in which the most efficient investments can be made to meet load [1]. Locational pricing in the utility sector is intended to align investment in energy resources with system needs.

DLMP follows the principles of LMP and applies it to the distribution network. DLMP is centred around the pricing of electric power at distribution nodes, which follows directly from the theory of spot pricing of electricity [2]. We define the DLMP price as the cost to serve the next unit of energy at a node on a distribution feeder. This is the cost from the perspective of the DNO, or Local Distribution Company (LDC) in Canadian contexts. DLMP prices are composed of three components which correspond to marginal costs of energy, loss, and congestion [3, 4] as defined in Chapter 2.

DLMP prices in a local market can be used to incentivise DER participation to support distribution network needs as part of a distribution-level energy market. Though this has not been implemented fully at utilities, pilot projects that experiment with DLMP pricing and dispatch are underway. For example, Opus One has deployed its software, GridOS Transactive Energy Management Systems (GridOS TEMS), on Hydro Ottawa Limited's (HOL) system as part of a project trial. GridOS TEMS allows HOL to operate a real-time shadow distribution market that generates cost-optimised dispatch schedules and DLMP prices for market participating DER. Through this market mechanism, DER that belongs to market participants are incentivised to provide energy services to HOL such that HOL's cost to serve its customers is minimised. In a live market, DER would then be compensated based on the DLMP applicable to their node in the distribution network. This would require regulatory permission to allow LDCs to operate live markets and source supply from customers. The DLMP pricing mechanism defines and accounts for network losses and congestion costs, which are otherwise not explicitly stated by LDCs or DNOs when compensating resources based on, for example, time-of-use or other DER-level rates.

1.2 Comparing Jurisdictions

In Canada, the UK, and across the globe, distribution-level energy and capacity markets are forecasted to serve as key components of a smart grid future in which DERs contribute to the resiliency, reliability, efficiency of the electric grid [5] [6], and democratisation of the grid. Within each jurisdiction, smart grid concepts are being explored and planned as per the existing distributor-customer relationship, or to-be-business models around the future of those relationships.

In general, it is agreed that the grid of the future will contain DERs, that those DERs will impact bulk and distribution level energy planning and operations, and that some entity or entities will coordinate the planning and operations of those DERs across bulk and distribution systems. The business models that follow from this agreement exist on a spectrum ranging from DER-owner control of resource operation and siting to transmission system operator full planning and control of DER.

Those two examples serve as extremes to paint a narrative. Interoperability-focused business models such as those in Figure 1 and from both UK and Ontario contexts, show worlds in which the distribution systems and transmission systems communicate with each other to simultaneously operate all resources based on their value to the grid.

For example, illustrated in Figure 1and Figure 2 are two extremes of the interoperability framework being explored in the UK through the Open Networks Project (ONP)[1]. The Open Networks Project is an Energy Networks Association (ENA) industry initiative that is focused on underpinning the delivery of the smart grid in the United Kingdom (UK). As per the ENA, the Open Networks Project *"seeks to enable the uptake of new smart energy technologies by more and more homes, businesses, and communities in the UK. Allowing customers to take advantage of these new technologies to take control of their energy will lower costs and secure the energy we rely on every day"* [1].

Workstream 3 of the ONP focusses on the transition to a Distribution System Operator (DSO). The ENA describes a DSO as an entity that *"securely operates and develops an active distribution system comprising networks, demand, generation and other flexible DER. As a neutral facilitator of an open and accessible market, it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation"* [2].

The output of this Workstream is five future worlds (A to E) that that model "*how future industry structures could best deliver flexibility markets providing services from DER for both national and regional (transmission and distribution) requirements***."** The ENA does not identify these worlds as mutually exclusive or complete, but instead as potential future market, organisational, and operational structures that could co-exist. World A and World D showcase frameworks in which flexible markets are managed and operated primarily by either DSOs or the Energy System Operators (ESO), the equivalent of a North American ISO respectively.

[1] https://www.energynetworks.org/creating-tomorrows-networks/open-networks

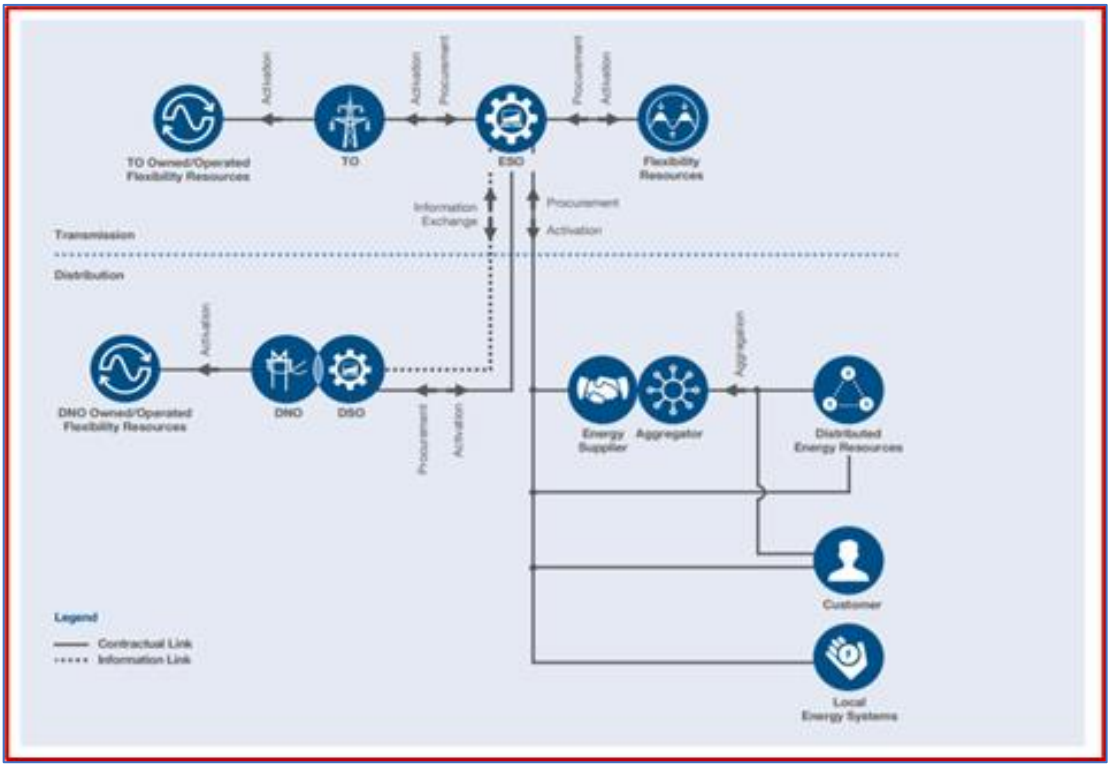

Figure 1: World A, DSO Coordinates, summarising a DSO-centric UK transmission-distribution interoperability model [2] (Page 16)

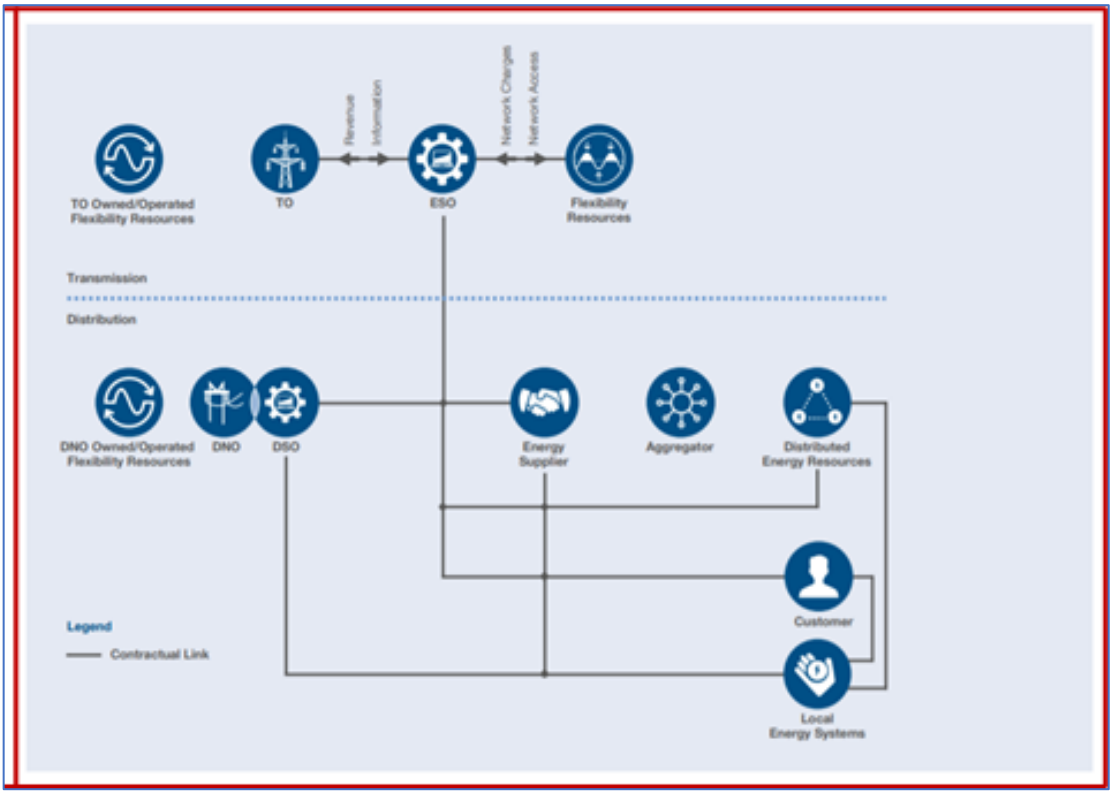

Figure 2: World D ESO-Coordinates, summarising an ESO-centric UK transmission-distribution interoperability model [2] (Page 23)

Similar to the industry projects initiated in the UK, the Ontario system operator (the IESO), has modelled a variety of future scenarios that would reflect distributed / embedded connected DER contributing to system needs as non-wires alternatives (NWAs) [3]. From this work, showcased in Figure 3, is a spectrum in which a Transmission System Operator (TSO) or DSOs may take lead in coordinating distribution-connected DER.

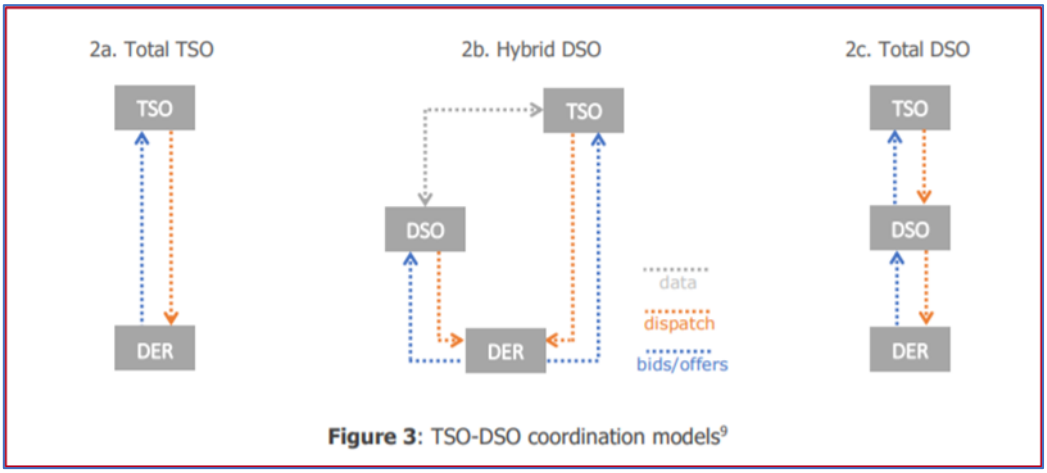

Figure 3: Coordination models reflecting transmission-distribution interoperability spectrum in Ontario, Canada [4]

Day-Ahead and Same-Day pricing (i.e. both are "spot pricing"), previously reserved for wholesale markets, is now being evaluated for use in distribution markets. How and whether to use spot pricing opens another set of questions beyond, though also dependent on, the DER-DSO-TSO or DER-DSO-ESO coordination models shown above.

The market model components that vary by jurisdiction are:

Energy Retail: in certain markets, distribution utilities purchase energy for resale to consumers. In other jurisdictions, retailers purchase electricity for resale to consumers, and pay the distribution utility for use of its infrastructure.

In markets where distribution utilities do not purchase energy for re-sale to end users, such as the UK, DSO services will likely focus on use of flexibility to resolve network constraints. In these markets, flexibility may be a service procured by an aggregator or prosumer, evaluated for safety and scheduled through a cost-minimising optimisation by the DSO.

In markets where distribution utilities do purchase energy for re-sale to end users, such as in Canada, DSO (in Canada, LDC) services may focus on both flexibility to mitigate network costs and flexibility to mitigate KWh usage.

In Ontario, Canada, the customer has a choice to purchase electricity through the distribution utility at a pass-through cost, or purchase it from a reseller. In either case, the customer pays the distribution utility for use of the grid.

Price Formation: Market Participants may either submit bids and offers to a market for evaluation and clearing by the DSO, or the DSO may bid a price for the participants to evaluate and decide whether to offer services in response.

When participants submit bids and offers, the price paid to each participant will generally be the highest price needed to balance supply and demand for a service, within both an interval and an evaluated region. This is called "the market clearing price" and is being piloted in Ontario as a part of trial initiatives. Additionally, there are price formation and market structures that would see each market participant compensated based on their bids and offers. These are differences shaped by the business rules of any market.

DER and System Operator Services: system operators in North America and Europe operate various markets including capacity, balancing, reserve, and energy markets plus they engage generation assets and DERs in contracts to meet grid needs. The thresholds for participation vary and thus shape the type of participants in system operator markets. There may be contexts in which DER are more or less likely to participate in transmission markets and/or hold contracts with system operators. Contributions of Flexibility providers to transmission markets and services impact the feasibility of spot market constructs and pricing methodologies.

Pricing methodologies and market structures should be designed to prevent unacceptable situations, such as gaming by a flexibility provider. Flexibility providers can either game participation in a market and/or receive market requests from a distribution market that conflict with market requests from a transmission market for the same, or dependent, time interval.

Dispatch & Payment Permissibility: regulation within a jurisdiction may allow or disallow a DSO from directly dispatching or compensating distribution-connected DER. This would impact whether the pricing methodology is developed to incentivise flexibility providers or to compensate them. This would also impact the ways in which a price calculated may relate to measurement and verification of market performance.

Network Model Quality: the quality and granularity of a DSO's network model will determine the granularity and accuracy of a price calculation that may rely on power flow analyses.

For example, in certain North American trials such as that at HOL, Opus One has generated and communicated through an operational platform DER-specific Distribution Locational Marginal Price (DLMP) in day-ahead and intra-day time periods to compensate DER. The DLMP is the incremental cost to serve a unit of load at a point in the network for a given period of time. The DLMP is calculated after an economic cost minimisation is performed that sets the dispatch levels of the DER for minimising the cost to run the system given voltage and current constraints.

For this schedule to be generated, a network model must be provided that contains the voltage and current constraints of the DSO's infrastructure. For more accurate dispatch and pricing, load forecasts at the nodal level must exist, and bids and offers from DER at the nodal level exist. The network models are typically housed within the utility. The bids and offers are typically submitted through a market. The nodal forecast loading and generation data may be created by the utility or a third-party software vendor.

2 DLMP Methodology

The DLMP Methodology is broken down into two key steps:

1. Calculation of system-cost minimising dispatch schedule for each resource for the period analysed
2. Calculation of the cost to serve an incremental unit of load for each interval at each resource analysed, given the schedule set in step 1.

In both day-ahead and intra-day markets, an optimal dispatch schedule is calculated for all resources in the distribution energy market. These schedules are obtained by running a time-series constrained alternating current (AC) unbalanced optimisation with the objective of minimising operating cost while respecting thermal limits. For each phase of a three-phase system, the current may be different, so each phase is independently optimised. Additionally, thermal limits refer to current and voltage constraints. In addition to optimal dispatch schedules, the solution to the constrained AC unbalanced optimisation includes the voltages at each node plus current, power, and losses across each line and transformer. From these, we the total cost to operate the network, total power drawn from the substation, and total network losses can be calculated. This is because this provides an accurate depiction of network conditions.

After running the AC unbalanced cost optimisation, the next step is to compute the DLMP and its corresponding energy, loss, and congestion components at each resource node.

To compute the energy and congestion prices, we linearise around the AC unbalanced solution, solve a linearised cost optimisation, and obtain the marginal values (i.e. shadow prices) of constraints which bind in the linearised problem. A constraint is considered to be binding if changing it also changes the optimal solution. The marginal cost of energy is determined by computing the marginal value of the power-balance constraint at the slack bus[2]. Other than when the system is fully supplied by DER, the marginal cost of energy is equal to the locational marginal price (LMP) at the slack bus (i.e., the substation bus) [3]. The marginal cost of energy represents the most competitive marginal offer that can serve the next unit of feeder load. In general, this is equal to the substation LMP or shadow price. However, when there exists a DER generator that is large enough to supply the next unit of load, and it has the most competitive marginal offer, then its offer will set the energy price. The marginal cost of congestion is determined by obtaining the marginal values of binding line or transformer current and power constraints, and then applying these marginal prices to each node using shift factors that represent the amount of power that would be transferred through a branch due to an injection at a given node. Borrowing from transmission system analyses, shift factors are defined as the change or sensitivity of active power flow in a reference direction a line with respect to a change in injection at the generator bus and a corresponding change in withdrawal at the reference bus [5].

Loss factor is the net change in system losses corresponding to an incremental change in injection at a single node. Computing loss factors requires performing an AC unbalanced power-flow analysis at each resource node at each timepoint. Figure 5 below summarises the inputs, outputs, and the key components of the DLMP methodology.

[2] Note: the slack bus is the node used to balance the active (kW) and reactive power (kVAR) needs of the system at a node, typically upstream, while performing load flow analyses such as power flow, or preferably optimal power flow. In Opus One's analyses, the slack bus is set to the analysed network's substation bus

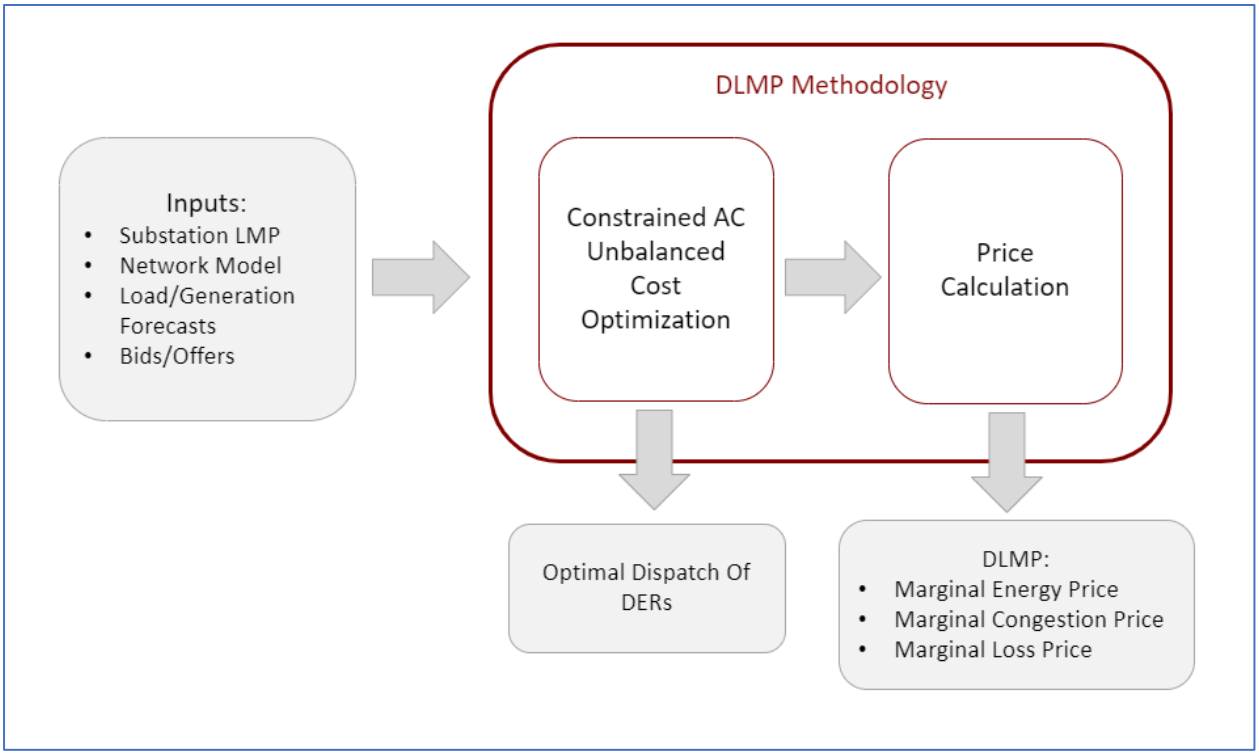

Figure 4: DLMP Methodology Inputs, Outputs and Key Components

2.1 DLMP Inputs

This section describes in further detail the inputs required for cost optimisation and DLMP calculation.

2.1.1 Network Model

The distribution network model format must conform to the IEC 61968 and IEC 61970 Common Information Model (CIM) standards. This deliberately allows for easy transfer of network model data as LDCs and DNOs do not use the same tools to store or translate network model data. CIM becomes the single, unified language that can be used to capture network model information from various sources of network data and the network model must contain the network connectivity, equipment ratings, and equipment phase information.

2.1.2 Resource Bids and Offers

Resources can submit bids or offers at every timepoint. Bid/Offer curves for all resources will be a set consisting of five elements: price, maximum capacity, interval start time, interval end time, and market type (i.e. intra-day or day-ahead).

The definitions of bids and offers are as follows:

- Bid
  - Bid price represents the *maximum* price a resource is willing to pay to consume energy [6].
  - Bid capacity represents the *maximum* amount of energy a resource is willing to consume. A market participant may be dispatched up to the bid capacity, with partial amounts of energy considered.
- Offer

- Offer price represents the *minimum* price a resource is willing to accept for producing energy [6].
- Offer capacity represents the *maximum* amount of energy a resource is willing to produce.

2.1.3 Substation LMP

The described DLMP Methodology requires substation locational marginal price (LMP) as an input. The LMP may vary by time point and market and can be a positive or negative value. A positive LMP indicates that the system will have to *pay* for power pulled from the substation; a negative LMP indicates that the system will *be paid* for by power pulled from the substation. This substation LMP forms the reference energy price for the evaluated system.

In a constraint management focused market, rather than an energy market, a substation energy price of "0" may be used to inform economic dispatch of constraint management resources. Use of a substation LMP of "0" and positive constraint management costs would result in no constraint management resources being dispatched for energy services, and instead those constraint management resources being dispatched to resolve constraints.

2.1.4 Load and Generation Forecasts

Load and generation forecasts are required as an input to the DLMP Methodology to inform network supply and demand in the economic dispatch analysis. Load forecasts can be provided at the feeder level or the nodal level. If nodal load forecasts are not available, feeder level forecasts may be allocated proportionally to each individual load based on their rating, or other data as available from the network operator.

Generation forecasts can be provided at the location or DER level, and allocated to each solar PV generator contained in the network model. If no solar generation forecast is available at the feeder or equipment level, GridOS will compute solar schedules based on a function that considers the location and nameplate ratings of the solar unit, and the time of year. If weather data (e.g. location and time-specific irradiance) are available, they may be included in the solar output forecast function too. At present this is only available for solar assets as they are the only assets that would be generating power and dispatching to the grid with or without a market and can be curtailed as a part of a market. Solar curtailment refers to dispatching a solar PV generator below its forecasted generation.

2.2 DLMP Methodology

The granularities of the DLMP methodology are proprietary to Opus One and are protected. At a high level, Opus One's DLMP methodology is comprised of two core functions:

1. A security constrained 3-phase AC unbalanced power flow optimisation that minimises the cost to operate the system in the evaluated scenario (e.g. minimising the cost incurred to resolve constraints through use of DER across all 24 hours jointly, rather than for each hour separately).
2. Conditional on the schedules set in function 1, an evaluation of the cost to serve an incremental unit of load at each evaluated DER node.

2.3 DLMP Outputs

The first step of this methodology -- the AC unbalanced cost minimisation -- will return, at each timepoint:

1. Optimal (i.e. cost-minimising) dispatch schedules for each resource
2. The total cost to operate the network
3. Voltages at each node and phase
4. Current, power and losses values at lines and transformers evaluated by the function

The second step of the DLMP methodology will output the DLMP values for each timepoint at each resource node. Each DLMP value will be decomposed into energy, loss, and congestion components.

2.4 DLMP Limitations and Assumptions

This methodology is developed for distribution systems and implemented on one network at a time. It is built based on the theory of calculating locational marginal pricing at the transmission level.

One of the assumptions is the modelling of the slack bus. It assumes that power balance can always be satisfied by purchasing power from the sub-transmission or transmission system. This limitation will be overcome in the future by modelling a distributed slack to represent the contributions from large generators and inter-ties with neighbouring networks.

Another limitation is the modelling of power transfers between adjacent networks and the impacts of power flows from one network to the other. This limitation can be worked around by performing this analysis on all interconnected distribution networks and modelling them as equivalent loads for performing this analysis on the sub-transmission and transmission level.

The development and implementation of DLMP is an actively researched topic. Opus One is one of the leading vendors that is trying to create a real world implementation of this concept and continuously strives to improve this implementation by working with utilities across the globe, sharing their experiences and taking their feedback into consideration.

3 Prototype Results

This section presents optimal dispatch schedules and DLMP values from running the above DLMP methodology on the IEEE13 distribution network.

The IEEE13 distribution feeder (shown in Figure 5) is one of the feeders published by the IEEE Power and Energy Society (PES), with the purpose of evaluating power flow algorithms for solving three-phase unbalanced networks. It operates at 4.16 kV, has unbalanced overhead and underground lines, a voltage regulator at the substation, unbalanced spot, shunt capacitors, and distributed loads.

The IEEE13 network has one distributed load located on line 632-671. It has been modelled as two spot loads in the following manner:

- one-third of the distributed load is modelled as a spot load located at the end of line 632-671 (i.e. node 671)
- two-thirds of the distributed load is modelled as a spot load located one-fourth of the way down line 632-671 from the source end (i.e. node 671a)

This method of modelling a distributed load model as two spot loads is called the "exact lumped model", and is an exact representation of the distributed load [7]. Basically, all the loads downstream of that node are characterised as one load at that node.

For demonstration purposes, three 5MW, unity power factor synchronous generators (with a power factor of 1) — Gen1, Gen2, and Gen3 — are added to nodes 633, 680 and 675, respectively. These generators will be submitting offers to the market. Also, a 1MW solar-PV generator is added at node 632.

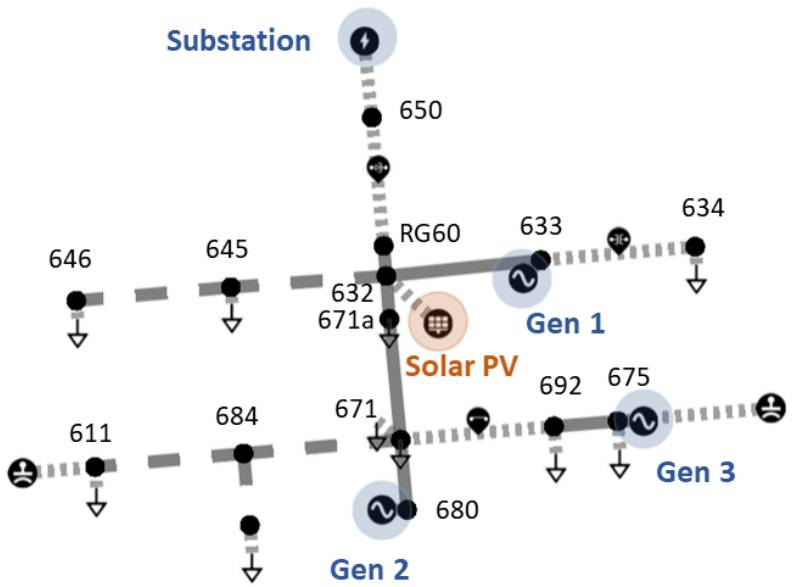

Figure 5: IEEE13 distribution network with three synchronous generators and a solar PV

The current carrying capacity i.e., ampacity, of the lines are:

Line	Ampacity [A]
632-645	B: 230, C: 230
645-646	B: 230, C: 230
632-633	A: 340, B: 340, C: 340
671-684	A: 230, C: 230
684-611	C: 230
684-652	A:165
671-680	A:730, B: 730, C: 730
692-675	A:100, B: 100, C:100
RG60-632	A:730, B: 730, C: 730
632-671a	A:730, B: 730, C: 730
671a-671	A:730, B: 730, C: 730

The power ratings of the transformer and voltage regulators are:

Voltage Transforming Devices	Rated Power [kVA]
650-632	N/A
633-634	500

When running cost optimisation on the scenarios below, it is ensured that voltage at any node and any phase do not deviate more than +/-6% from the nominal voltage (i.e. voltages are between 0.94pu - 1.06pu).

3.1 Scenarios

Six different scenarios are studied in this section to illustrate the effectiveness of the implemented DLMP methodology on the modified IEEE13 distribution network. In each scenario, the results are compared relative to the base case (i.e. Scenario 1). The studied scenarios are as follows:

1. Network Under Normal Loading;
2. Network Under Normal Loading, Competitive Market;
3. Network Under Normal Loading with High Losses;
4. Network Under Normal Loading with PV Generation;
5. Network Under High Loading Due to EV Charging;
6. Network Under Normal Loading, Large Generator Capacity;

As a note, the prototype is focused on generating DLMP values that represent the cost to serve the next unit of load at any node. These scenarios do not display amounts that market participating DER would be compensated; this is determined based on the business rules and structures of local transactive energy/flexibility markets.

3.1.1 Network Under Normal Loading

This scenario represents a network under normal loading. The substation LMP is 15$/MWh. First, consider the case where the three synchronous generators do not submit any offers, and the solar-PV unit is not generating power. The substation supplies all the power to the load, which results in all nodal voltages falling within the operating range of 0.94-1.06pu, and no current or power violations across any of the lines or transformers. The total substation power is 3.862MW, the total loss in the network is 0.109MW, and the total cost to run the network for one hour is 57.93$.

Now, consider the case where the three generators participate in the market with the offers specified in Figure 6.

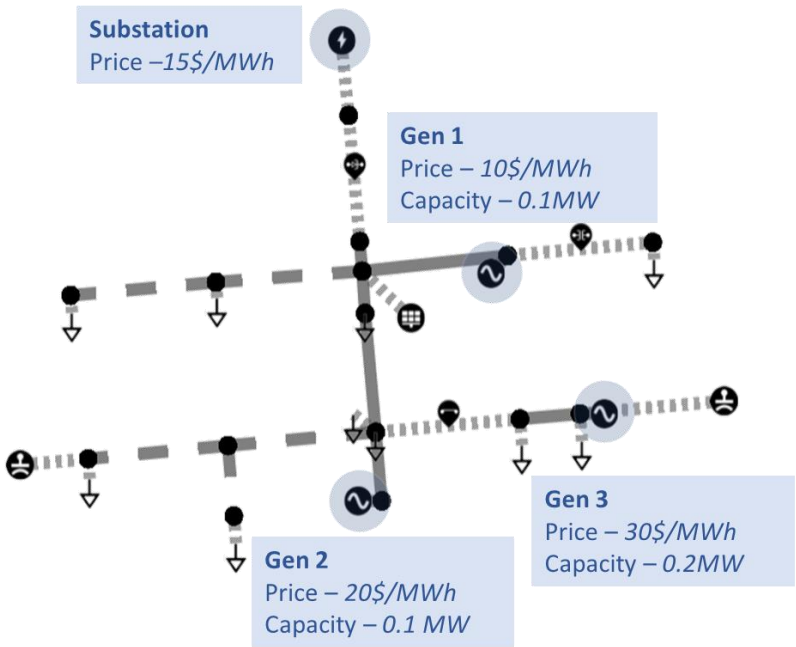

Figure 6: IEEE network with three synchronous generators (in blue) and their offered prices

Running a cost optimisation results in *Gen1* being fully dispatched, since its offer is the lowest price for energy (10$/MWh) in the evaluated system and below the LMP. The substation, which in the evaluated system offers the second lowest price for energy (15$/MWh), supplies power for the remaining load. *Gen2* and *Gen3* are not dispatched. Because of the cost optimisation, total system losses and total operating costs are reduced, as shown in Table 1. Moreover, the cost optimisation does not compromise system reliability, as voltages remain between 0.94-1.06pu and there are no current or power violations.

Table 1: Summary of Cost Optimisation for Scenario #1

	Scenario #1 - No Resources	Scenario #1 – With Resources
Substation Generation [MW]	3.862	3.759
Total Solar Generation [MW]	0	0
Total Load [MW]	3.753	3.753
Total Losses [MW]	0.109	0.106
Total Cost [$]	57.93	57.39
Min/Max Voltage [p.u.]	0.96/1.04	0.96/1.04
Max Line/Xfmr Loading [p.u.]	0.79	0.78

DLMPs at each node are shown in Table 2. The marginal energy price for all nodes is the substation LMP (15$/MWh). For losses, *Gen3* has the highest marginal loss price (0.85$/MWh), indicating that, of all the generators, it would be the most effective at reducing system losses if its generation were to be increased. *Gen1* has the lowest loss price, indicating that it is less effective at reducing losses under the proposed dispatch schedule. The congestion price is zero for all resources, since there is no line or transformer congestion in this scenario. Overall, since *Gen1* is the only unit where the nodal DLMP is higher than its offered price, it is the only unit which will be dispatched. The remaining load

will be provided by the substation that has a 15$/MWh offer price, making it the next most economic unit in the evaluated system.

Table 2: DLMP Results for Scenario #1

Resources/ Substation	Offer Price [$/MWh]	Optimal Dispatch [MWh]	DLMP [$/MWh]			
			Energy	Congestion	Loss	DLMP
Substation	15	3.759	15	0	0.00	15.00
Gen1	10	0.1	15	0	0.47	15.47
Gen2	20	0	15	0	0.84	15.84
Gen3	30	0	15	0	0.85	15.85

3.1.2 Network Under Normal Loading, Competitive Market

In this scenario, the network load is the same as in Scenario #1, and the solar-PV unit is not generating power. As such, running a cost optimisation without the three synchronous machines participating yields the same result as running cost optimisation on Scenario #1, where the total cost to run the network for one hour is 57.93$.

Now consider the case where the three generators are participating in the market. In this scenario, all the resources submit offers that are similar to the substation LMP –offer price of *Gen1* is 14.5$/MWh, price at *Gen2* is 15.5$/MWh, and price at *Gen3* is 16$/MWh (See Figure 7). The rated capacities of the resources are the same as in Scenario #1, and the PV unit is not dispatching any power.

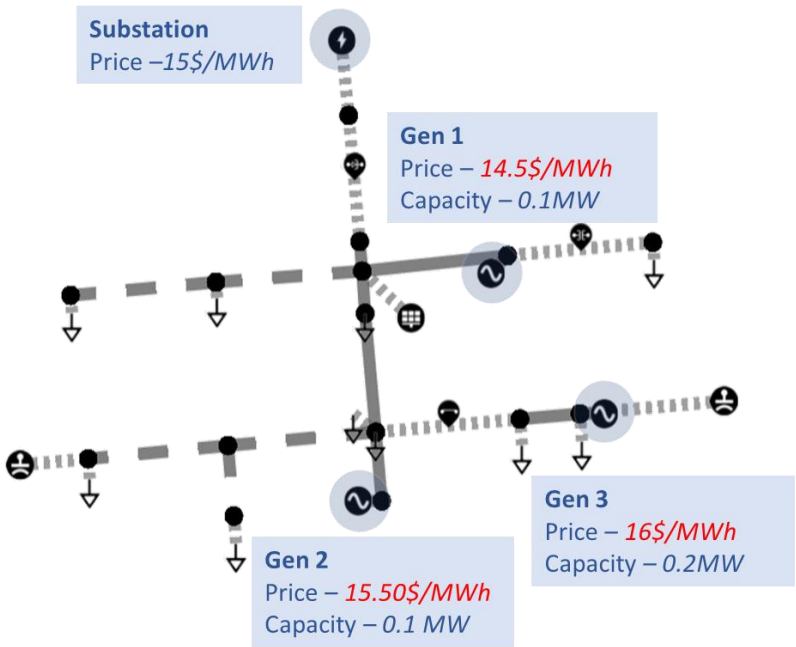

Figure 7: Resource offered prices similar to the LMP

Running a cost optimisation results in *Gen1* and *Gen2* being fully dispatched, and the substation supplying the remaining load. Note that *Gen2* is being dispatched even though it is more expensive than the substation. This indicates that it is cheaper to dispatch *Gen*2 than to incur losses transmitting power from the substation. As a result of the cost optimisation, total system losses and total operating costs are reduced, as shown in Table 3.

Table 3: Summary of Cost Optimisation for Scenario #2

	Scenario #2 - No Resources	Scenario #2 - With Resources
Substation Generation [MW]	3.862	3.654
Total Solar Generation [MW]	0	0
Total Load [MW]	3.753	3.754
Total Losses [MW]	0.109	0.100
Total Cost [$]	57.93	57.36
Min/Max Voltage [p.u.]	0.96/1.04	0.96/1.04
Max Line/Xfmr Loading [p.u.]	0.79	0.80

As in Scenario #1, the marginal energy cost is at 15$/MWh for all nodes, and the congestion is 0$/MWh as there is no line congestion. The loss price of *Gen2* causes the DLMP at that node to be above its offer price, and consequently leads to *Gen2* to be fully dispatched (See Table 4).

Table 4: DLMP Results for Scenario #2

Resources/ Substation	Offer Price [$/MWh]	Optimal Dispatch [MW]	DLMP [$/MWh]			
			Energy	Congestion	Loss	DLMP
Substation	15	3.654	15	0	0.00	15.00
Gen1	14.5	0.1	15	0	0.46	15.46
Gen2	15.5	0.1	15	0	0.80	15.80
Gen3	16	0	15	0	0.82	15.82

3.1.3 Network Under Normal Loading With High Losses

In this scenario, the length of the highlighted AC line in Figure 8 is increased by 75%. The network load is the same as Scenario #1, and the solar PV unit is not generating power. First, consider the case where the three synchronous machines are not participating in the market. The substation supplies all the power to the load, which results in all nodal voltages falling within the operating range of 0.94-1.06pu and no current or power violations across any of the lines or transformers. Note that due to the line length increase, the total losses are increased from 0.109MW to 0.130MW, and total cost increases from 57.93$ to 58.09$.

Now consider the case where the three generators are participating in the market. The offered prices and the rated capacity of all resources are the same as in Scenario #1, and the PV unit is not dispatching any power.

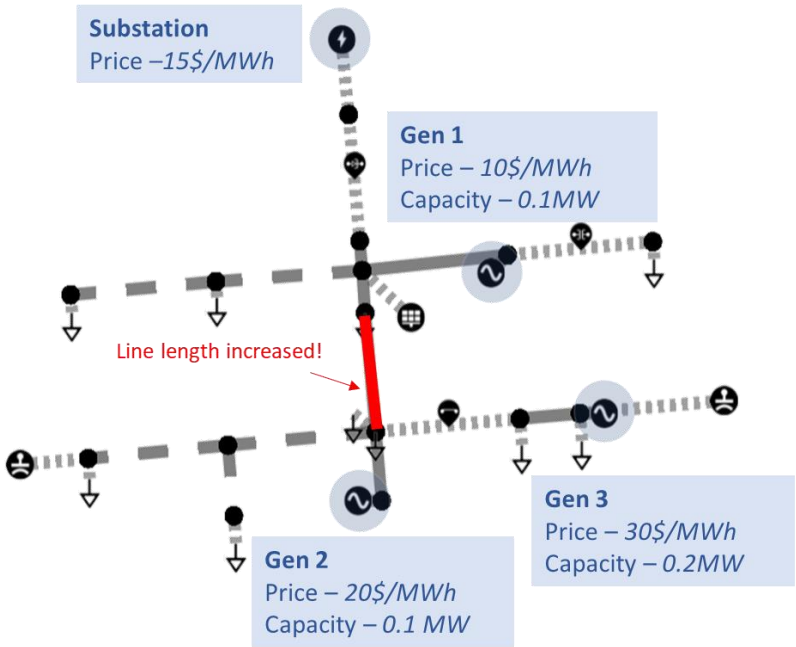

Figure 8: Network with Long AC line (in red)

Running a cost optimisation results in the same dispatch schedule as Scenario #1 (i.e. *Gen1* is fully dispatched, and the substation supplies power for the remaining load). As a result of the cost optimisation, total system losses and total operating costs are reduced as shown in Table 5. Moreover, the cost optimisation does not compromise system reliability, as voltages remain between 0.94-1.06pu, and there are no current, power or voltage violations.

Table 5: Summary of Cost Optimisation for Scenario #3

	Scenario #3 - No Resources	Scenario #3 – With Resources
Substation Generation [MW]	3.873	3.770
Total Solar Generation [MW]	0	0
Total Load [MW]	3.743	3.74
Total Losses [MW]	0.130	0.126
Total Cost [$]	58.09	57.59
Min/Max Voltage [p.u.]	0.94/1.04	0.94/1.04
Max Line/Xfmr Loading [p.u.]	0.80	0.79

DLMPs at each resource node are shown in Table 6. Again, the marginal energy price for all nodes is the substation LMP (15$/MWh).

As in Scenario #1, *Gen2* and *Gen3* have higher marginal loss prices than *Gen1*. This is because *Gen2* and *Gen3* are downstream of the long AC line and can consequently reduce a greater amount of system loss than *Gen1,* which is located upstream of the long line. Moreover, in comparison to Scenario #1, the loss price for both *Gen2* and *Gen3* have increased by 0.27$/MWh. Since the losses in the long AC line have increased, there is a higher incentive for *Gen 2* and *Gen 3* to reduce losses – however, it is still not enough for them to be dispatched, since their offers are too high. Only *Gen 1* is dispatched, since its offer is below the DLMP of 15.48$/MWh

As in Scenario #1, there is no marginal congestion price at the resources' nodes, because there is neither line nor transformer congestion.

Table 6: DLMP Results for Scenario #3

Resources/ Substation	Offer Price [$/MWh]	Optimal Dispatch [MW]	DLMP [$/MWh]			
			Energy	Congestion	Loss	DLMP
Substation	15	3.772	15	0	0.00	15.00
Gen1	10	0.1	15	0	0.48	15.48
Gen2	20	0	15	0	1.11	16.11
Gen3	30	0	15	0	1.12	16.12

3.1.4 Network Under Normal Loading with PV Generation

In this scenario, the network is under normal loading; however, the PV unit, shown in Figure 9, is also generating power. The offer prices of the resources are the same as Scenario #1.

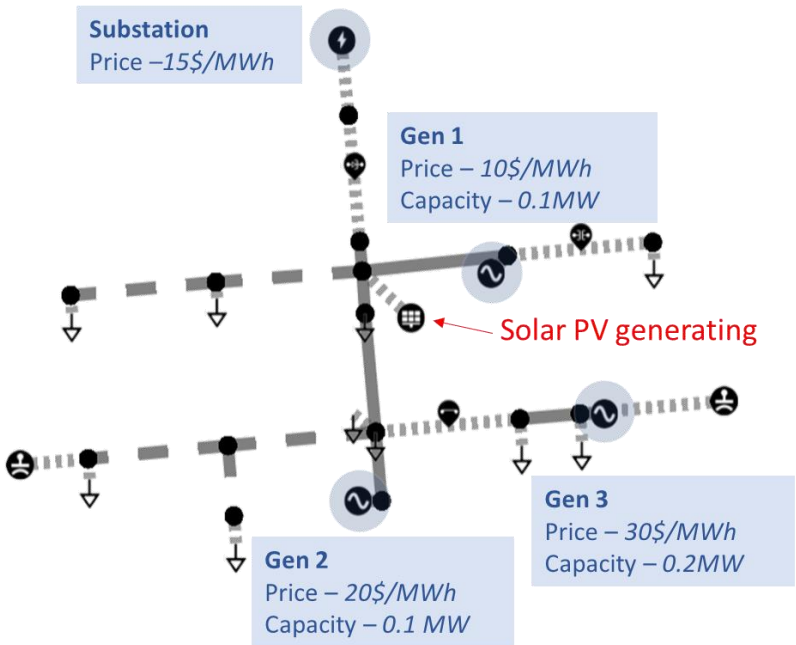

Figure 9: Network With PV generation

Note that solar-PV generation helps to reduce losses in the network, even prior to running a cost optimisation. The results of running the cost dispatch on this network are shown in Table 7; *Gen1* is still the only unit dispatched, as it has the cheapest offer. The remaining load is fed from the substation. Overall, running a cost optimisation reduces the total loss and the total cost of generation operation in comparison to the base case where there are no resources.

Table 7: Summary of Cost Optimisation for Scenario #4

	Scenario #4 - No Resources	Scenario #4 – With Resources
Substation Generation [MW]	3.711	3.247

Total Solar Generation [MW]	0.5	0.5
Total Load [MW]	3.755	3.755
Total Losses [MW]	0.0945	0.0917
Total Cost [$]	55.67	49.71
Min/Max Voltage [p.u.]	0.96/1.04	0.97/1.04
Max Line/Xfmr Loading [p.u.]	0.78	0.70

Comparing these results with Scenario #1 DLMPs, all resources are receiving lower loss price. This is because the solar PV unit is already offsetting some losses, reducing the losses impact of generation by other resources. DLMP results are show in Table 8.

Table 8: DLMP Results for Scenario #4

Resources/ Substation	Offer Price [$/MWh]	Optimal Dispatch [MW]	DLMP [$/MWh]			
			Energy	Congestion	Loss	DLMP
Substation	15	3.247	15	0	0.00	15.00
Gen1	10	0.1	15	0	0.41	15.41
Gen2	20	0	15	0	0.77	15.77
Gen3	30	0	15	0	0.78	15.78

3.1.5 Network Under High Loading Due to EV Charging

In this case study, an EV is connected to node 675, co-located with *Gen3,* which results in an increment to the overall load on that node by 445kW. On the other hand, according to the standard IEEE13-bus feeder data, the AC line connected to this node (highlighted in Figure 10) has a low thermal limit, meaning that this additional demand for EV charging will cause congestion. Cost optimisation and DLMPs were calculated with the same offered prices as Scenario #1. The solar PV unit is not generating power. Results are shown in Table 9 and Table 10.

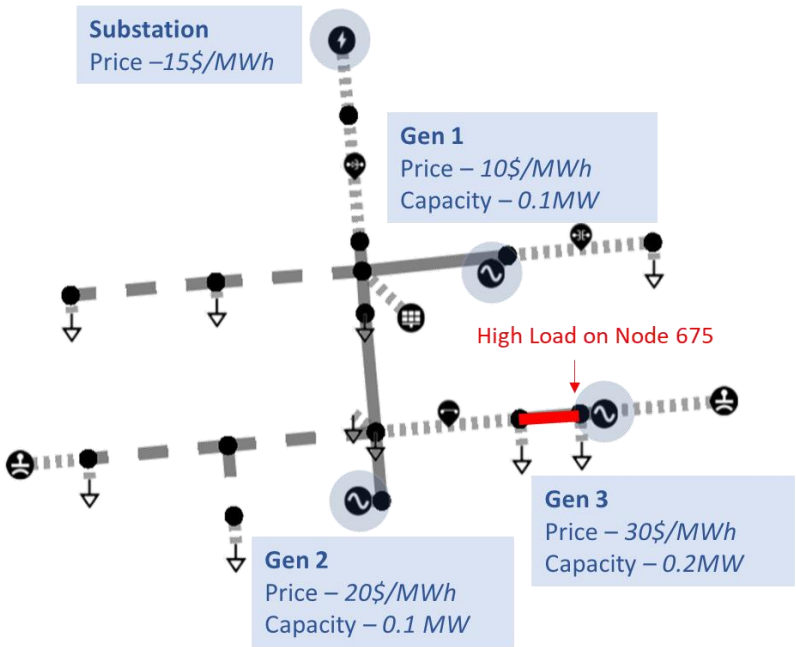

Figure 10: High loading on Node 675 Causing Line Congestion (in red)

Considering the results presented in Table 9, the cost optimisation improves system performance by dispatching *Gen3* to avoid overloading elements in the system. The total cost of operation increases, since an expensive generator was the only asset that addressed the line congestion. Also, the overall system loss is reduced by dispatching both *Gen1* and *Gen3*.

Table 9: Summary of Cost Optimisation for Scenario #5

	Scenario #5 - No Resources	Scenario #5 - With Resources
Substation Generation [MW]	4.332	4.114
Total Solar Generation [MW]	0	0
Total Load [MW]	4.196	4.197
Total Losses [MW]	0.136	0.125
Total Cost [$]	64.98	65.98
Min/Max Voltage [p.u.]	0.96/1.04	0.96/1.04
Max Line/Xfmr Loading [p.u.]	1.104	0.99
Congestion	Congested AC line	No congestion

Gen3 is incentivised with positive marginal prices on loss and congestion, resulting in a DLMP equal to its offer price. Therefore, in this scenario, both *Gen1* and *Gen3* will be dispatched. *Gen3* receives a positive congestion price because, if this unit generates power, it can prevent a violation on the AC line. Although Gen3 has the highest offered price, it is being dispatched to help the system overcome

the congestion cause by a sudden increased load on node 675. The fact that the DLMP at node 675 is equal to the offer price for Gen3 is important too – congestion prices make up the difference between the cost of a generator responding to congestion versus the cost to serve that load if there was no congestion.

Table 10: DLMP Results for Scenario #5

Generators/ Substation	Offer Price [$/MWh]	Optimal Dispatch [MW]	DLMP [$/MWh]			
			Energy	Congestion	Loss	DLMP
Substation	15	4.114	15	0	0.00	15.00
Gen1	10	0.1	15	0	0.54	15.54
Gen2	20	0	15	0	0.98	15.98
Gen3	30	0.109	15	13.97	1.03	30

3.1.6 Network Under Normal Loading, Large Generator Capacity

Consider a scenario where *Gen1* receives an upgrade. Its generation capacity is increased from 0.1MW to 3MW and it maintains an offer price of 10$/MWh. This generator can provide a lot of cheaper energy; however, it cannot be fully utilised because of limited capacity on the AC line connecting node 633 to node 632 (highlighted in Figure 11). The results of running the cost optimisation on this scenario are presented in Table 11. The DLMPs are shown in Table 12.

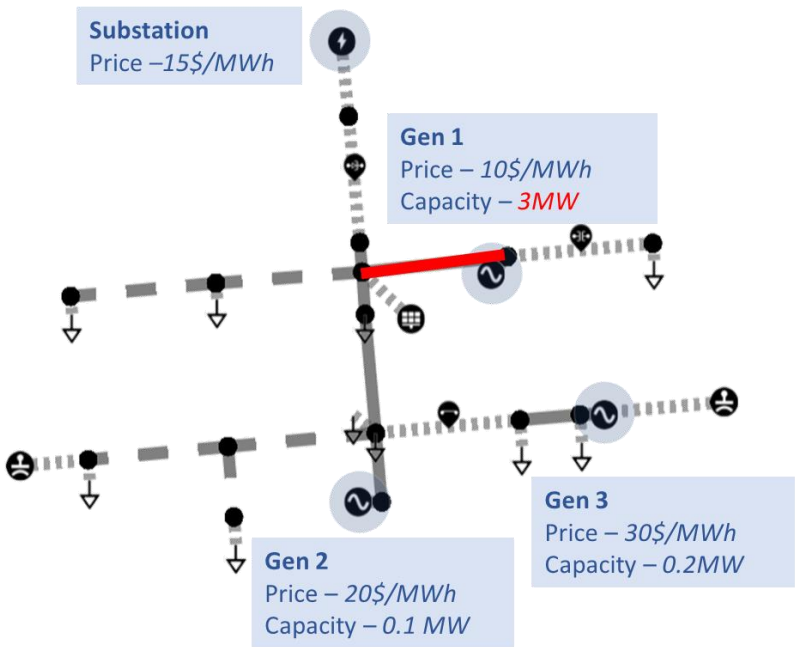

Figure 11: Increased Capacity at Gen 1

The results of Table 11 reveal that cost optimisation can considerably reduce the overall system loss and the total cost of generation by dispatching *Gen1*. However, this cheap market resource cannot be fully dispatched, due to congestion. As such, some of the load is fed by the substation.

Table 11: Summary of Cost Optimisation for Scenario #6

	Scenario #6 - No Resources	Scenario #6 – With Resources
Substation Generation [MW]	3.862	1.160
Total Solar Generation [MW]	0	0
Total Load [MW]	3.753	3.764
Total Losses [MW]	0.109	0.074
Total Cost [$]	57.93	44.18
Min/Max Voltage [p.u.]	0.96/1.04	0.98/1.04
Max Line/Xfmr Loading [p.u.]	0.79	0.99

From Table 12, observe that there are negative loss and congestion prices applied to node 633, reducing the DLMP at that node below the marginal energy cost to the offer price of *Gen1*. Further generation at this node is being dis-incentivised because it would induce additional losses and lead to congestion on the system. Unlike previous scenarios, *Gen1* is only partially dispatched, indicating that the system provider cannot buy as much power from *Gen1* as would be desirable because of congestion. In addition, the negative marginal loss component indicates that increasing the dispatch of *Gen1* would lead to higher system losses. This indicates that most of the losses in the system are incurred transmitting power from *Gen1* to the loads on the system.

Table 12: DLMP Results for Scenario #6

Generators/ Substation	Offer Price [$/MWh]	Optimal Dispatch [MW]	DLMP [$/MWh]			
			Energy	Congestion	Loss	DLMP
Substation	15	1.160	15	0	0.00	15.00
Gen1	10	2.678	15	-4.95	-0.05	10.00
Gen2	20	0	15	0	0.53	15.53
Gen3	30	0	15	0	0.54	15.54

3.2 Conclusion

The scenarios discussed herein reveal that applying cost optimisation to distribution systems through the use of DLMP generally improves the power system performance by contributing to cost reduction and preventing systems from experiencing congestion. Table 13 summarises the results for all six scenarios for a better comparison.

High-level takeaways from the scenario results to confirm the DLMP methodology include confirming that:

- Overall cost to operate the distribution network is reduced when assets are made available for economic dispatch
- DLMP is the sum of energy, loss, and congestion prices
- DLMP loss components vary by node, and so by DER
- Generators are dispatched only when their DLMP is higher than the generator offer price, and only to the extent that their dispatch will reduce system cost
- PV generation is accounted for in economic dispatch and price signal generation such that loss prices of downstream generators are decreased to reflect load served through PV generation
- Generators are incentivised to dispatch by a higher DLMP when their location, capacity, and offer provide potential for congestion relief. Under this condition, cost to operate the distribution network may be increased, but congestion is relieved.
- Large generators, even if cheap to dispatch, that may constrain the network are dis-incentivised from dispatching, and only to the extent that their dispatch will constrain the network

Table 13: Cost Optimisation and DLMP Results for Six Studied Scenarios

Scenarios	Results						
	Generators/ Substation	Offer Price	Optimal Dispatch [MW]	DLMP [$/MWh]			
				Energy	Congestion	Loss	DLMP
#1: Normal Loading	Substation	15	3.759	15	0	0	15.00
	Gen1	10	0.1	15	0	0.47	15.47
	Gen2	20	0	15	0	0.84	15.84
	Gen3	30	0	15	0	0.85	15.85
#2: Normal Loading, Competitive Market	Substation	15	3.654	15	0	0	15.00
	Gen1	14.5	0.1	15	0	0.46	15.46
	Gen2	15.5	0.1	15	0	0.80	15.80
	Gen3	16	0	15	0	0.82	15.82
#3: Normal Loading with Long Lines	Substation	15	3.772	15	0	0	15.00
	Gen1	10	0.1	15	0	0.48	15.48
	Gen2	20	0	15	0	1.11	16.11
	Gen3	30	0	15	0	1.12	16.12
#4: Normal Loading with PV Generation	Substation	15	3.247	15	0	0	15.00
	Gen1	10	0.1	15	0	0.41	15.41
	Gen 2	20	0	15	0	0.77	15.77
	Gen 3	30	0	15	0	0.78	15.78
	Substation	15	4.114	15	0	0	15.00
	Gen1	10	0.1	15	0	0.54	15.54

#5: High Loading Due To EV Charging	Gen2	20	0	15	0	0.98	15.98
	Gen3	30	0.109	15	13.97	1.03	30.00
#6: Normal Loading, Large Generator Capacity	Substation	15	1.160	15	0	0	15.00
	Gen1	10	2.678	15	-4.95	-0.05	10.00
	Gen2	20	0	15	0	0.53	15.53
	Gen3	30	0	15	0	0.54	15.54

While DLMP as a pricing methodology is being trialed and experimented, its full implementation and any market operations rely on a number of other factors, namely:

- A communication methodology is required to facilitate operations that would see market participants receive, provide, or confirm dispatch. This can be met by platforms such as Opus One's GridOS or by communication protocols such as the Universal Smart Energy Framework (USEF) [8]
- A set of market structures and rules that govern the ways in which system operators and market participants agree on and are settled for market services, respectively. This might include:
    - Outlining settlement values relative to DLMP prices, as presented in section 1.21.2 Comparing Jurisdictions
    - Timing market operations such as bid submission, bid clearance, dispatch, and settlement
    - Determining penalties associated with non-compliance and/or non-delivery
- An integration with utility operations processes such that control room operators have visibility of asset dispatch from a local market.
- Availability of measurement & metering data to support market validation and market participant compensation

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