EVALUATION METHODOLOGY OVERVIEW FOR IDER COMPETITIVE SOLICITATIONS

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EVALUATION METHODOLOGY OVERVIEW FOR IDER COMPETITIVE SOLICITATIONS

A. EVALUATION PROCESS OVERVIEW

The electric utilities employ Least Cost, Best Fit (LCBF) principles in evaluation process of their existing solicitations such as Renewable Portfolio Standard (RPS), CHP, SCE's Local Capacity Requirement (LCR), and All Source RFO for RA and energy. In accordance with D.04-12-048, LCBF methodology takes into account the qualitative and quantitative attributes associated with bids to obtain the best value and most cost effective solutions for the electric customers.

The results from an evaluation will inform selection of Offers with which IOU will enter into negotiations. An evaluation methodology is developed and implemented under the oversight of the Independent Evaluator (IE), the Procurement Review Group (PRG), and Energy Division (ED) staff.

In general, the electric utilities' evaluation process consists of three steps:

- Initial screen
- Quantitative valuation
- Qualitative evaluation including selection constraints

1. Initial Screen

Once bids are received for a solicitation, an initial review is performed for the completeness and conformity of the offers with the solicitation protocol. The review parameters include conforming delivery point, conforming commercial on-line date, conforming term, conforming operating requirements, minimum/maximum project size, any interconnection requirements. If sellers lack any of the requirements, electric utilities allow a reasonable cure period and work directly with the sellers to remedy those deficiencies. Once the cure period is over, the data of all the conforming bids is gathered and made ready for further steps of evaluation.

2. Quantitative Valuation

For quantitative valuation, Net Present Value (NPV) calculations are performed for each bid. The NPV analysis entails (1) projecting various benefits and costs streams over the life of the bid proposal, (2) applying time value of the money, and (3) estimating total net present value as present value of benefits minus present value of costs.

The electric utilities develop their market price forecasts using proprietary models for ascribing value to various attributes like RA capacity, electrical energy, ancillary services, RPS credits, and GHG allowances. The quantity of these attributes are projected based on bid specifications, guidance from CPUC/CAISO rules, dispatch models or generation profiles. For load reducers, the quantity of these attributes is estimated on the reduced requirement basis.

3. Qualitative evaluation including selection constraints

The attributes that cannot be reasonably quantified are characterized as qualitative. These qualitative attributes include portfolio diversity, seller concentration, overall utility's portfolio position and need, site diversity, interconnection status. The qualitative considerations are reviewed along with quantitative results during selection process. The selection method can vary from simple rank ordering based on evaluation metrics to complex optimization. The optimization model is warranted when there is specific set of constraints to meet portfolio requirement, and/or there are mutual inclusivity or exclusivity conditions offered by the bidders. Setting qualitative factors as selection constraints is another of way of implicitly attributing quantitative value to these factors. The optimization is generally done on the iterative basis to review various cost-effective solutions along with the other qualitative factors that could not be considered as selection constraints.

B. PRINCIPLES FOR DEVELOPING SOLICITATION EVALUATION METHODOLOGY FOR CSF

In developing the solicitation evaluation methodology for DER procurement, CSFWG had consensus on using LCBF framework. For valuation of deferred distribution upgrade, the group proposed to base it on the approach being developed as part of DRP's LNBA methodology for location-specific deferral value. In addition, CSFWG agreed upon the following set of principles:

1. Consider the potential services beyond what is asked in the solicitation and other conceivable benefits/costs provided by DERs as qualitative factors

The additional value provided by DERs at secondary level include enhanced grid services provided by advanced smart inverter, potential market price suppression due to reduced need, potential equipment life extension/reduction. Such type of attributes cannot be reasonably quantified today, but can be used as bids differentiator through qualitative factors when applicable.

2. Continue to refine the evaluation methodology as new market rules and potential values/costs develop, and integrate "lessons learned"

DERs to defer distribution need is a new market we are embarking into, it will, in turn, potentially give way to new products, services and rules. CSFWG identified the need to continually refine the evaluation methodology to reflect the new market developments to ensure accurate and fair valuation. The "lessons learned" should also be integrated in the evaluation process as our understanding of both positive and adverse impact of DER adoption on the electric system advances.

3. Avoid double counting of benefits and costs

As we continue to augment the traditional list of values provided by a resource of RA, energy and AS, there is a need to ensure that benefits and costs are being accounted for accurately and any double counting issues should be thoroughly discussed and avoided.

C. EVALUATION METHODOLOGY

CSFWG discussed the below set of quantitative and qualitative factors.

1. Quantitative Factors

Quantitative factors include Net Market Value (NMV). NMV intends to represent the value of an Offer from the market perspective. The NMV captures the market value provided by an Offer of Energy, A/S, and Capacity and compares it to the Offer's cost. NMV is calculated for each Offer as follows:

Net Market Value in levelized $/kW-year: NMV = Benefits - Costs
Where Benefits =
RA (Capacity) Value
Energy Value
Ancillary Services Value
RPS Benefit
Reduced GHG Emissions Benefit
Renewable Integration Cost/Reduced Cost Benefit
Distribution Deferral Value
Transmission Deferral Value
And Costs =
Contract Payments Costs (including Fixed and Variable Costs)

a. RA Value Benefit

The RA (including system, local and flexible) amount attributed to each resource is established under the guidance of the current NQC counting rules of the CPUC. As new rules are implemented, the methodologies to determine RA capacity for the associated resources are replaced to reflect new guidance. If a resource's operational capabilities generally fall under a category described by the CPUC for RA counting rules, the rules are applied directly. When no such category is identified, electric utilities may use program/technology specific studies/proceedings to estimate the impact of resource on peak load or assess the contribution to peak load through their own analysis.

The resources that act as load reducers may receive adjustments to their RA quantity benefits to reflect avoided T&D losses and RA reserve margin requirements.

The RA price forecast is developed from multiple sources and assumptions such as market transacted data from utilities' own previous solicitations, local requirements, long term capacity value, cost of generation studies, and planning reserve margin assessment. There is inherent uncertainty in the RA price forecasts, therefore there is no guarantee that the ascribed RA value to a resource during the time of solicitation will be realized in the future.

b. Energy Value Benefit

The energy amount attributed to must-take and baseload resources is based on the bid's expected generation delivery profile. For dispatchable resources, operations of the resource are projected using the economic dispatch principle based on bid's operating characteristics, operating costs and market services offered.

The resources that act as load reducers may receive adjustments to their energy quantity benefits to reflect avoided losses.

The energy price forecast is generally established using forward market data and fundamental model prices. The location-specific adjustment are done to reflect associated congestion value forecasts. As discussed for RA price forecast, there is inherent uncertainty in the energy price forecasts, therefore there is no guarantee that the ascribed energy value to a resource during the time of solicitation will be realized in the future.

c. Ancillary Services Value Benefit

The ancillary services (A/S) amount is projected based on first determining if a resource is capable of providing A/S. If the resource can provide A/S, then similar methodologies as energy amount forecast are used to determine A/S amount to be attributed to the resource.

The A/S price forecast could be based on historical market data, statistical model or fundamental model. As discussed above for RA and energy price forecast, there is inherent uncertainty in the A/S price forecasts, therefore there is no guarantee that the ascribed A/S value to a resource during the time of solicitation will be realized in the future.

d. RPS Benefit

The eligible renewable DERs that count towards utilities' RPS compliance requirement get RPS benefit. Their RPS benefit quantity is calculated from their generation delivery profile. The load reducing DERs also get RPS benefit as they result in reduction in utility's RPS compliance requirement. The reduced RPS compliance requirement is calculated based on total reduced bundled load projection from the resource and RPS standard targets.

The electric utilities forecast REC value from their own RPS solicitations data, third party vendors' subscribed data and public market reports.

e. Reduced GHG Emissions Benefit

The load reducing DERs or renewable DGs get the benefit of not have any combustion-related GHG compliance obligation and corresponding costs. There is not separate quantification of this benefit as DERs receive the value of avoiding GHG emissions via the value of reduced generation need energy costs. The emission costs are embedded into LMP prices.

f. Renewable Integration Cost/Reduced Cost Benefit

The renewable resources integration requires flexible resources that the utility and/or the CAISO can control to manage and firm-up intermittent output. For the DG resources where renewable integration cost is applicable, Renewable Integration Cost Adder (RICA) methodology from RPS proceeding is generally employed.

Certain DERs can reduce the cost of integrating intermittent renewable generation by providing the operational flexibility that the system needs. By providing such flexibility, the system operation costs are reduced which otherwise have been incurred in acquiring flexible resources. However, to the extent this benefit is captured in flexible RA or ancillary services value, it is appropriate to not double count this benefit.

g. Distribution Deferral Value

As identified in DRP's LNBA methodology, deferred distribution components would include

a. Sub-transmission, Substation and Feeder Capital and Operating Expenditures

b. Distribution Voltage and Power Quality Capital and Operating Expenditures

c. Distribution Reliability and Resiliency Capital and Operating Expenditures

The CSFWG has proposed to develop deferral values using Real Economic Carrying Charge (RECC) method based on the approach being developed in the DRP. See Section F below for an example calculation.

The benefit of distribution deferral will be evaluated for DERs that are located on identified substations and/or feeders. Such benefit will be assessed based on the deferred cost of the least expensive traditional solution meeting the identified operational need on that distribution location, i.e., the project that would most likely be built in the DERs' absence. The main factors in the analysis for each alternative include the installed cost, the operating and maintenance cost, project life, return on investment, and discount rate.

h. Transmission Deferral Value

There are various public processes that determine the required transmission projects in the CAISO controlled grid, and the utilities also conduct their own transmission reliability assessment in parallel to CAISO's Transmission Planning Process. Using the cost of traditional grid investment and by identifying specific system characteristics (or needs) driving the need for the transmission projects, a deferral value or avoided cost may be calculated. The factors like interrelationship between transmission system planning and distribution system planning, coincident peak between DER and transmission need will be taken into account to determine any potential contribution of DERs in deferring transmission capital and operating expenditure.

i. Contract Payments Costs

The contract costs could be composed of capacity payments and/or energy payments, i.e., fixed costs and variable costs. The energy payments could be associated with generation as all-in cost for DG type of resources, or variable costs for demand response/energy storage type of resources.

2. Qualitative Factors

Qualitative factors include: "Project Viability," "Voltage and Other Power Quality Services," "Equipment Life Extension," "Societal Benefits" and "Other Factors."

a. Project Viability

The project viability assessment includes factors such as developer experience, O&M experience (proven track record), commercial technology, reasonableness of delivery date, and interconnection progress.

b. Voltage and Other Power Quality Services

The voltage and other power quality services stream that are not identified as DER portfolio need during solicitation, but deemed to be providing value to the system are also considered while selecting bids.

c. Equipment Life Extension

If certain DER bids are deemed to have impact on extending/reducing the distribution equipment life, the attribute would be considered as part of qualitative consideration while selection, as secondary benefit or cost.

d. Societal Benefits

Where identified, societal benefits or costs include public benefits or costs that do not have any nexus to utility rates. The societal benefits attribute is planned to be leveraged from various other proceedings like DRP's LNBA methodology, IDER's demand side cost effectiveness. Rather than duplicative efforts, it is best of the societal benefits be addressed in Phase III of the IDER, as was proposed by the CEWG. It is appropriate to include any societal benefit that can clearly be linked to the deployment of the proposed product.

e. Other Factors

Other factors include considerations like supplier diversity, counterparty concentration, site diversity, technology/end-use diversity to help market transformation

D. Other Discussion POINTS [placeholder]

1. DER counting rules

Similar to RA counting rules, the counting rules for projected reactive power deliveries and other services will need to be developed for different DERs.

2. Headroom for DER portfolio size

There will be a headroom needed for solicited DER portfolio size relative to the identified distribution capacity need due to:

a. The risk of contracts fall-out

The cost effectiveness of DERs relative to the distribution asset will be done at a portfolio level. If the contracts within the portfolio fall-out, then that poses the risk of new portfolio being cost effective at the later time. Some headroom will need to be built during initial portfolio design based on contracts success rate expectations.

b. Achieving similar performance characteristics as distribution asset

[…]

E. Illustrative example of quantitative and qualitative considerations

Electric Distribution Planning analysis has identified a distribution upgrade due to overload and voltage violations at on XYZ circuit during summer peak condition. An alternative to traditional "wires" solution could be DER portfolio with following operating attributes:

Distribution capacity need	3 MW

Voltage support service need	0.7 MVAR
Months when needed	Aug – Sep
Time when needed	13:00 - 20:00
Duration	4 hours
Location	60% in area A and 40% in area B of XYZ circuit

For the determination of optimal DER portfolio, the illustrative evaluation steps consist of

1. First, the valuation using quantitative factors is performed to get the least cost bids.
2. Next, the parameters of DERs portfolio requirement like location, timing, and voltage support capacity are set as selection constraint in optimization. The optimization model selects the bids that satisfy the constraints at least cost.
3. If a DER provides other power quality services beyond what is being procured through the solicitation like Conservation Voltage Reduction, the further review is done. It is assessed how much incremental cost is being incurred for the additional service and determined if that DER provides better value for the customers.
4. In addition, other qualitative factors are considered such as project viability, counterparty concentration etc. when reviewing several portfolios.

F. Illustrative calculation of distribution investment deferral benefit

The formula for calculating an investment deferral benefit—for a single period and infinite stream—as used by PG&E is as follows:

$$TD[Proj][y] = \frac{TDCapital[y][inv] * Inflation[inv] * RRScaler[y][inv] * \left(1 - \left(\frac{1 + i[inv]}{1 + r}\right)^{\Delta t}\right)}{(1 + r)^{(y - StartYr)}}$$

The following is an illustrative example of a \$5 million investment that is deferred for ten years. Assume the traditional investment has a thirty year life. The present value of the deferral benefit for a single period is \$2,278,821 and the present value of an infinite steam of such traditional investments is \$3,145,593.

		Single Period	Infinite Stream
TD[Proj][y]=	Value of investment deferral project in year y.	$2,278,821	$ 3,145,593
TD[Proj]=	Transmission or distribution project		
[y]=	The year the investment is committed.	2017	
TDCapital[y][inv]=	Capital cost of the investment in year y.	$5,000,000	
[inv]=	The investment deferral project, i.e., the investment is part of the T&D project		

Inflation[inv]=	(1+i[inv])^(y-BaseYear[inv]). Convert investment to nominal dollars in the in-service year.	1.00
i[inv]=	Inflation rate for the investment, e.g., the general inflation rate.	2.5%
r=	Discount rate.	7%
BaseYear[inv]=	Year basis for cost estimate for the investment.	2017
RRScaler[y][inv]=	Revenue requirement scaling factor to convert direct capital costs to revenue requirement levels.	1.49
D*t*=	The lifetime of the investment.	10.0
StartYr=	First year of the economic analysis.	2015
	formula result within parentheses=	0.3493
n =	periodicity of investment (for PV of infinite stream) in years	30

The following formula is used to convert the present value of the deferral value of a single period traditional investment into a deferral value for an infinite steam of traditional investments.

Where PV of infinite stream (PV_∞) is defined below; r is the discount rate and i is the inflation rate. The present value should be a beginning of year, if EOY gross-up by (1 + discount rate) to BOY. The present value of an infinite stream for a project is calculated according to the formula:

$$PV_\infty = PV_1 * \left[\frac{1}{1-\left(\frac{1+i}{1+r}\right)^n} \right]$$