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Publication Date

2023-12-11

Peer reviewed



Lawrence Berkeley National Laboratory

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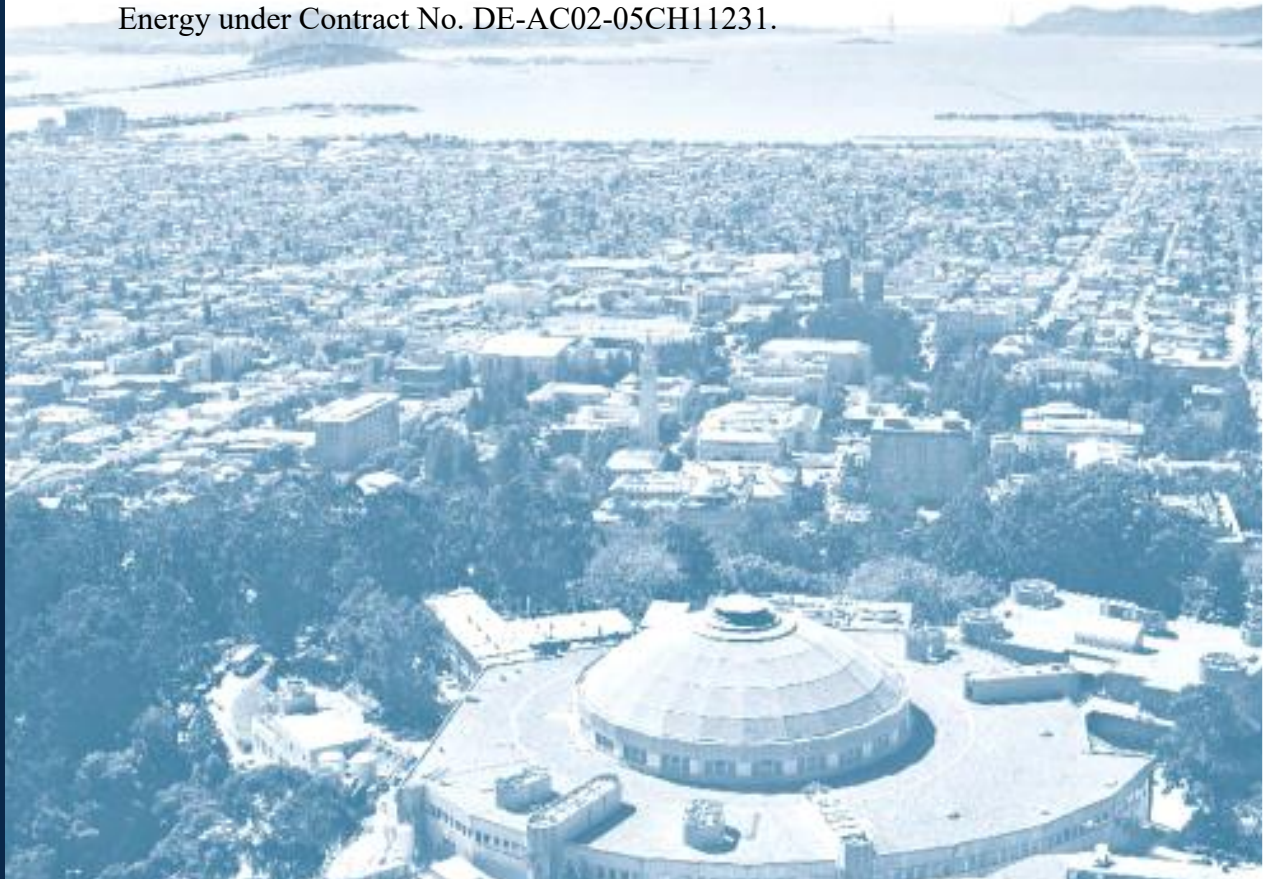
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To be published in Energy

April 2017

Partial funding for this work was provided by the Office of Electricity Delivery
and Energy Reliability, Distributed Energy Program of the U.S. Department of
Energy under Contract No. DE-AC02-05CH11231.



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The impact of Ancillary Services in optimal DER investment decisions

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Abstract

Microgrid resource sizing problems typically include the analysis of a combination of value streams such as peak shaving, load shifting, or load scheduling, which support the economic feasibility of the microgrid deployment. However, microgrid benefits can go beyond these, and the ability to provide ancillary grid services such as frequency regulation or spinning and non-spinning reserves is well known, despite typically not being considered in resource sizing problems. This paper proposes the expansion of the Distributed Energy Resources Customer Adoption Model (DER-CAM), a state-of-the-art microgrid resource sizing model, to include revenue streams resulting from the participation in ancillary service markets. Results suggest that participation in such markets may not only influence the optimum resource sizing, but also the operational dispatch, with results being strongly influenced by the exact market requirements and clearing prices.

Keywords

Microgrid, ancillary services, decision support tool, optimization, distributed energy resources, mixed integer linear programming

1. Introduction

Microgrids, defined as clusters of small sources, storage systems, and loads, which presents themselves to the main grid as single, flexible, and controllable entities [1,2], have recently been attracted considerable attention from both academia and industry due to their potential benefits. These include the ability to reduce costs of energy delivery as well as alleviate environmental burdens due to increased efficiency in supply, but also to increase system resiliency and reliability, particularly in the event of natural disasters and prolonged outages. By introducing dispatchable generation and storage assets, microgrids can be a valuable resource to the main grid and potentially contribute to issues such as hosting capacity or upgrade deferrals, while also being naturally more independent from it. While this creates settings for added flexibility in grid operation, microgrids are complex systems that require specific infrastructure, resource coordination, and information flows, as well as added layers of protection and power quality assurance. The added costs resulting from the need to meet these conditions can

35 potentially jeopardize the economic viability of microgrids, and therefore it is fundamental to take into
36 account all different revenue streams, both direct and indirect, that result from microgrid deployment [3].

37 Several methods are proposed in the literature to address the problem of sizing DER assets in microgrids.
38 Simulation-based models are commonly found [4–8], but mathematical programming or optimization
39 algorithms are equally available. In this domain, the most commonly used approaches are mixed integer
40 linear programming (MILP) models [9–13], and mixed integer non-linear programming (MINLP) models
41 [14,15].

42 Analyzing the fundamental differences between these approaches, simulation models generally have the
43 advantage of being straightforward to develop, solve extremely fast, and allow non-linear behaviors can
44 be easily modeled. Their main drawback is that they tend to rely heavily on user input and prior knowledge
45 to build candidate solutions, and considering different objectives (e.g. changing from cost minimization,
46 to CO₂ minimization) typically requires developing separate algorithms. In addition, simulation models do
47 not guarantee that an optimal solution is found, which can be a key limitation in large problems where
48 multiple technology options are available and defining candidate solutions can be extremely complex.
49 Popular examples of commercial software belonging to this category includes HOMER [5,6] or RETSCREEN
50 [7].

51 In contrast, optimization algorithms have the main advantage of guaranteeing optimality provided a
52 convex feasible region is created, and typically do not require user intervention to define a feasible
53 solution space. However, optimization models can become extremely large and require very significant
54 computational power, potentially leading to intractable cases. Different approaches exist within the
55 domain of optimization algorithms, with the main distinction regarding the nature of the objective
56 function and constraints, particularly on linearity. Linear and mixed-integer linear models tend to have fast
57 solution times, albeit at the cost of potentially losing accuracy in the representation of non-linear effects.
58 An example of a publicly available MILP model used for microgrid resource sizing is the Distributed Energy
59 Resources – Customer Adoption Model (DER-CAM) [9–11], although other similar models may be found
60 in literature [16–18], with key differences being the number and type of technologies considered, the data
61 granularity and time horizon, the exact definition of the objective function, and the number of energy
62 carriers and end-uses being considered. Nonlinear and mixed-integer nonlinear (MINLP) models, on the
63 other hand, add complexity and detail that MILP models may fail to capture, by explicitly including non-
64 linearity in their formulation. While this may more accurately model the behavior of different
65 technologies, it is often followed by the downside that finding a solution may not be possible due to the
66 non-convexities occurring in the search space. Examples of such models can be found in [14,15,19].

67 More in-depth reviews of the different methodologies used for optimal microgrid resource sizing can be
68 found in [20–22].

69 While microgrid resource sizing tools typically consider key revenue streams such as peak shaving, load
70 shifting, or power exports, very little emphasis is given to revenues resulting from the participation in
71 ancillary service (AS) markets, although their potential is known and has been widely identified [23–26].

72 The most common ancillary service markets include spinning and non-spinning reserve, as well as
73 frequency up- and down-regulation, although other markets such as black start, reactive supply and

74 voltage regulation also exist. These markets often operate using a bidding structure, where awarded bids
75 are required to guarantee the service they have bid for, and while the exact rules depend on the different
76 markets operated within each ISO, each market is typically characterized by different requirements
77 including the time to react to a utility signal, the minimum asset size, or bid duration [27]. A detailed
78 analysis of different AS markets currently operating in the United States can be found in [28].

79 Different studies have addressed operational strategies to use microgrid resources for AS provision,
80 although they do not take into account potential revenues in the process of microgrid design. Namely, in
81 [29] and [30] the participation of microgrids in ancillary service markets as an alternative to conventional
82 generation and storage is discussed, covering both participation frequency regulation markets and voltage
83 control. Specifically, the work presented in [29] introduces an adaptive hill climbing strategy to develop a
84 central demand response (DR) algorithm, which the authors refer to as “Central Direct Load Control”. The
85 results presented in this work suggest that microgrid generation and storage assets can successfully be
86 leveraged to regulate the system frequency and voltage while minimizing the amount of manipulated
87 responsive loads needed to keep the frequency within the desired range. In a more recent work, authors
88 [30] present a new framework for the coordination of distributed energy resources (DER) and DR, in order
89 to support voltage and frequency in islanded microgrids. In this work that is formulated as a multi-
90 objective problem and is solved by particle swarm optimization, the loads are classified into controllable
91 and non-controllable categories. The results demonstrate that the proposed control strategy works
92 effectively for different generation and consumption patterns. Another method that aims to improve a
93 microgrid resilience following an unplanned islanding is presented in [31], where the microgrid is
94 equipped with DERs, energy storage, and electric vehicles. A DR strategy is deployed that curtails pre-
95 defined low-priority loads. The objective is to minimize the amount of load curtailed, while ensuring the
96 microgrid stability in terms of energy balance and frequency control. This method was proven effective
97 for short periods of islanding.

98 While surveying the existing literature suggests that both microgrid resource sizing problems and the
99 potential benefits from ancillary service market participation are well-known, little work has been done
100 regarding the inclusion of AS revenue streams in the process of finding optimal DER capacity for
101 microgrids. This paper contributes to bridging this gap and builds on the state-of-the-art by introducing
102 revenue streams from AS market participation in DER and microgrid sizing problems. Particularly, this is
103 done by leveraging on DER-CAM, a state-of-the-art MILP optimization model used for microgrid sizing,
104 and implementing support for the most common AS market products.

105 The remaining of this paper is organized as follows: In section 2, the mathematical formulation of DER-
106 CAM is presented, along with changes introduced during this work. In section 3 a case study is introduced
107 to demonstrate the inclusion of AS market revenues in microgrid sizing problems, including all key data
108 used. Section 4 discusses the results obtained, and in Section 5 the key conclusions are presented.

109 **2. DER-CAM**

110 **2.1. Overview, Objective, and Applications**

111 The Distributed Energy Resources – Customer Adoption Model (DER-CAM) is a state-of-the-art decision
112 support tool for decentralized energy systems, including buildings and microgrids, and has been
113 developed by the Lawrence Berkeley National Laboratory. DER-CAM determines the optimal mix and
114 capacity of the DERs, as well as the optimal dispatch of these resources, for a microgrid under different
115 settings. DER-CAM is formulated as a Mixed Integer Linear Program (MILP), where the key inputs include
116 customer loads broken into several end-uses; cost and performance characteristics of generation and
117 storage technologies (e.g., investment cost, operation and maintenance costs, efficiency, heat-to-power
118 ratio maximum operating hours, etc.); and electric and natural gas tariffs. The tool outputs optimal
119 investment and operation decisions, including annual energy costs; optimal DER capacities; optimal
120 dispatch of DERs; and load management measures. The objective of the model is to find the optimal
121 combination of technology adoption and operation to supply all energy services required by the site under
122 consideration, while optimizing the energy flows to minimize costs and / or CO₂ emissions.

123 The targeted user-groups of DER-CAM include microgrid owners and site operators, industry stakeholders
124 including equipment manufacturers, and policy makers. Key applications for microgrid owners and site
125 operators include optimized investment recommendations based on site-specific loads, tariffs, and
126 objectives. Applications for Industry stakeholders include identifying cost and performance characteristics
127 that will lead to adoption of their technologies in diverse segments of the market. For policy makers, key
128 DER-CAM applications include determining high-level impacts on distributed energy resource penetration
129 levels, and anticipating customer adoption behaviors given changes in electricity rates, demand-response
130 programs, and different regulations.

131 In previous iterations of DER-CAM, the most relevant revenue streams included in the process of microgrid
132 sizing consisted of savings due to avoided utility purchase, peak shaving, load shifting, and power exports.
133 Specifically, DER-CAM considers exporting power through the application of feed-in tariffs, and different
134 demand-response programs are supported, including time-of-use rates, power demand charges, and
135 direct load control, all of which are considered in the objective function.

136 **2.2. DER-CAM formulation**

137 A simplified version of the original DER-CAM formulation, i.e. the formulation prior to the modifications
138 proposed in this paper is presented in this section, as introduced in [11,32,33]. In this deterministic model,
139 customer loads are modeled with 3 typical day-types (week, peak, and weekend) per month with hourly
140 time-steps. The objective is to minimize operational and investment costs over a typical year, where the
141 investment costs are being annualized using an annuity rate that depends on the interest rate and
142 technology lifetime. We model capacity of DER technologies using a continuous or discrete variable: If a
143 technology is available in small enough modules (e.g. photovoltaic and storage), the optimal capacity is
144 modeled as a continuous variable, significantly lowering the computation time. Discrete variables are used
145 otherwise (e.g. micro-turbines).

146 Indices

147 c continuous generation technologies: photovoltaic panels (PV), and absorption chillers (AC)

148 g discrete generation technologies: internal combustion engines (ICE), micro-turbines (MT), gas
149 turbines (GT), and fuel cells (FC)

150 i set of all technologies ($j \cup k$)

151 j set of all generation technologies ($g \cup c$)

152 k storage technologies: stationary storage (ES), and thermal storage (TH)

153 p tariff period {on-peak, mid-peak, off-peak}

154 s season {winter, summer}

155 u end-use: electricity only (eo), cooling (cl), refrigeration (rf), space heating (sh), water heating (wh),
156 and natural gas only (ng)

157 m, d, h month {1, 2, ..., 12}, day type {1, 2, 3}, hour {1, 2, ..., 24}

158 Customer loads

159 $Load_{m,d,h,u}$ customer load at time m, d, h for end-use u [kW]

160 Market data

161 $TP_{s,p}$ regulated demand (power) charges under the default tariff for season s and period p [\$/kW]

162 $TE_{m,d,h}$ regulated tariff for electricity at time m, d, h [\$/kWh]

163 TF_m regulated tariff fixed charge for electricity in month m [\$/]

164 $TE_{x,m,d,h}$ regulated tariff for electricity export at time m, d, h [\$/kWh]

165 NGF_m regulated tariff fixed charge for natural gas in month m [\$/]

166 NGP_m regulated tariff for natural gas in month m [\$/kWh]

167 Technology data

168 $MaxP_g$ rated capacity of generation tech. g [kW]

169 $MinL_g$ minimum acceptable load for generation tech. g [kW]

170 Lt_i expected lifetime of technology i [a]

171 CCD_g turnkey capital cost of generation technology g [\$/kW]

172 $FCC_{(c,k)}$ fixed capital cost of generation technology c or storage technology k [\$/]

173 $VCC_{(c,k)}$ variable capital cost of generation tech. c or storage technology k [\$/kW]

174 $VCSC_k$ variable capital cost of storage technology k [\$/kWh]

175 OMF_i fixed annual operation and maintenance costs of technology i [\$/kW]

176 OMV_i variable operation and maintenance costs of technology i [\$/kWh]

177 $MaxH_j$ maximum number of hours technology j can operate during the year, [h]

178 $VC_{j,m}$ generation cost of technology j during month m [\$/kWh]

179 $S(j)$ set of end-uses that can be met by technology j [-]

180 α_j heat to power ratio: units of useful heat that can be recovered from a unit of electricity generated
181 by technology j [1]

182 SCE_k charging efficiency of storage technology k [%]

183 SDE_k discharging efficiency of storage technology k [%]

184 φ_k losses due to decay/self-discharge in storage technology k [%]

185 MSC_k minimum state of charge of storage technology k , [%]

186 COP_u central microgrid chillers coefficient of performance [1]

187 COP_a absorption chillers coefficient of performance [1]

188 SPE_c theoretical peak solar conversion efficiency of generation technology c [%]

189 $SRE_{c,m,h}$ solar radiation conversion efficiency of generation technology c , in month m , and hour h
190 [%]

191 Other parameters

192 IR interest rate on DER investments [%]

193 An_i annuity factor for investments in technologies i [1]

194 $SI_{m,d,h}$ solar insolation at time m , d , h [kW/m²]

195 SA available area for solar technologies [m²]

196 β_u units of heat energy generated from a unit of natural gas energy purchased for end-use u [1]

197 BAU total energy costs in the business-as-usual case, obtained by running the model with investments
198 disabled [\\$]

199 PBP maximum payback period allowed on the integrated DER investment decision [a]

200 Decision Variables

201 IG_g number of units of generation technology g installed [1]

202 $RG_{g,m,d,h}$ number of units of generation technology g operating at time m , d , h [1]

203 $GU_{j,m,d,h,u}$ power generated by technology j , at time m , d , h for end-use u [kW]

204 $GS_{j,m,d,h}$ power generated to export by technology j , at time m , d , h [kW]

205 $RH_{j,m,d,h}$ useful heat recovered from technology j , at time m , d , h [kW]

206 $AL_{m,d,h}$ heat used to drive absorption chillers at time m , d , h [kW]

- 207 $Cap_{(c,k)}$ rated output of generation technology c or storage technology k [kW]
208 $ECap_k$ energy capacity of storage tech. k [kWh]
209 $SOC_{k,m,d,h}$ state of charge of storage technology k at time m, d, h [kWh]
210 $SIn_{k,m,d,h}$ energy input to storage technology k, at time m, d, h [kW]
211 $SOut_{k,m,d,h,u}$ energy output from storage technology k, at time m, d, h for end use u [kW]
212 $sb_{k,m,d,h}$ binary charge/discharge decision of storage technology k at time m, d, h [b]
213 $psb_{m,d,h}$ binary decision of purchasing or selling electricity at time m, d, h [b]
214 $NGU_{m,d,h,u}$ natural gas purchase at time m, d, h for end-use u [kWh]
215 $UL_{m,d,h,u}$ electricity purchased from power utility at time m, d, h for end-use u [kW]
216 $Pur_{(c,k)}$ customer purchase binary decision of technology c or k [b]
217 Economic objective function

$$\begin{aligned}
\min C = & \sum_m TF_m & [\$] & (1) \\
& + \sum_m \sum_d \sum_h \sum_u UL_{m,d,h,u} \cdot TE_{m,d,h} \\
& + \sum_s \sum_{m \in S} \sum_p TP_{s,p} \cdot \max(\sum_{u \in \{eo, cl, rf\}} UL_{m,(d,h) \in p, u}) \\
& + \sum_j \sum_m \sum_d \sum_h (GS_{j,m,d,h} + \sum_u GU_{j,m,d,h,u}) \cdot (VC_{j,m} + OMV_j) \\
& + \sum_g IG_g \cdot MaxP_g \cdot (CCD_g \cdot An_g + OMF_g) \\
& + \sum_{i \in c,k} ((FCC_i \cdot Pur_i + VCC_i \cdot Cap_i + VCSC_k \cdot ECap_k) \cdot An_i + Cap_i \cdot OMF_i) \\
& + \sum_m NGF_m \\
& + \sum_m \sum_d \sum_h \sum_u NGU_{m,d,h,u} \cdot NGP_m \\
& - \sum_j \sum_m \sum_d \sum_h GS_{j,m,d,h} \cdot TEx_{m,d,h}
\end{aligned}$$

218 Microgrid constraints

$$Load_{m,d,h,u} + \frac{SIn_{k,m,d,h}}{SCE_k} = SOut_{k,m,d,h,u} \cdot SDE_k + \sum_j GU_{j,m,d,h,u} + UL_{m,d,h,u} \quad \forall m, d, h: k = \{ES\} \wedge u = \{eo\} \quad [kW] \quad (2)$$

$$Load_{m,d,h,u} + \frac{SIn_{k,m,d,h}}{SCE_k} + AL_{m,d,h} = SOut_{k,m,d,h,u} \cdot SDE_k + \beta_u \cdot NGU_{m,d,h,u} + \sum_g RH_{g,m,d,h,u} \quad \forall m, d, h: k = \{TH\} \wedge u \in \{sh, wh\} \quad [kW] \quad (3)$$

$$Load_{m,d,h,u} = \sum_j GU_{j,m,d,h,u} + UL_{m,d,h,u} \cdot COP_u \quad \forall m, d, h: u \in \{cl, rf\} \quad [kW] \quad (4)$$

$$Load_{m,d,h,u} = NGU_{m,d,h,u} \quad \forall m, d, h: u = \{ng\} \quad [kW] \quad (5)$$

$$RG_{g,m,d,h} \cdot MinL_g \leq \sum_u GU_{g,m,d,h,u} + GS_{g,m,d,h} \leq RG_{g,m,d,h} \cdot MaxP_g \quad \forall g, m, d, h \quad [kW] \quad (6)$$

$$\sum_m \sum_d \sum_h (\sum_u GU_{g,m,d,h,u} + GS_{g,m,d,h}) \leq IG_g \cdot \text{MaxP}_g \cdot \text{MaxH}_g \quad \forall g, m, d, h \quad [\text{kW}] \quad (7)$$

$$\sum_u RH_{g,m,d,h,u} \leq \alpha_g \cdot (\sum_u GU_{g,m,d,h,u} + GS_{g,m,d,h}) \quad \forall g, m, d, h \quad [\text{kW}] \quad (8)$$

$$Cap_i \leq Pur_i \cdot \mathbf{M} \quad \forall i \in \{c, k\} \quad [\text{kW}] \quad (9)$$

$$\sum_u GU_{c,m,d,h,u} + GS_{c,m,d,h} \leq Cap_c \cdot \frac{SRE_{c,m,h}}{SPE_c} \cdot SI_{m,d,h} \quad \forall m, d, h : c \in \{\text{PV}\} \quad [\text{kW}] \quad (10)$$

$$\sum_c \frac{Cap_c}{SPE_c} \leq SA : c \in \{\text{PV}\} \quad [\text{m}^2] \quad (11)$$

$$SOC_{k,m,d,h} = Sin_{k,m,d,h} - \sum_u SOut_{k,m,d,h,u} + SOC_{k,m,d,h-1} \cdot (1 - \varphi_k) \quad \forall k, m, d, h \neq 1 \quad [\text{kWh}] \quad (12)$$

$$SOC_{k,m,d,1} = SOC_{k,m,d,24} \quad \forall k, m, d \quad [\text{kWh}] \quad (13)$$

$$SOC_{k,m,d,h} \geq ECap_k \cdot MSC_k \quad \forall k, m, d, h \quad [\text{kWh}] \quad (14)$$

$$SOC_{k,m,d,h} \leq ECap_k \quad \forall k, m, d, h \quad [\text{kWh}] \quad (15)$$

$$Sin_{k,m,d,h} \leq Cap_k \quad \forall k, m, d, h \quad [\text{kW}] \quad (16)$$

$$\sum_u SOut_{k,m,d,h,u} \leq Cap_k \quad \forall k, m, d, h \quad [\text{kW}] \quad (17)$$

$$Sin_{k,m,d,h} \leq sb_{k,m,d,h} \cdot \mathbf{M} \quad \forall k, m, d, h \quad [\text{kW}] \quad (18)$$

$$\sum_u SOut_{k,m,d,h,u} \leq (1 - sb_{k,m,d,h}) \cdot \mathbf{M} \quad \forall k, m, d, h \quad [\text{kW}] \quad (19)$$

$$GU_{j,m,d,h,u} = AL_{m,d,h} \cdot COP_a \quad \forall m, d, h : j = \{\text{AC}\} \wedge u = \{\text{cl, rf}\} \quad [\text{kW}] \quad (20)$$

$$\sum_u UL_{m,d,h,u} \leq psb_{m,d,h} \cdot \mathbf{M} \quad \forall m, d, h : u = \{\text{eo, cl, rf}\} \quad [\text{kW}] \quad (21)$$

$$GS_{j,m,d,h} \leq (1 - psb_{m,d,h}) \cdot \mathbf{M} \quad \forall j, m, d, h \quad [\text{kW}] \quad (22)$$

$$An_i = \frac{IR}{\left(1 - \frac{1}{(1+IR)^{Lt_i}}\right)} \quad \forall i \quad [1] \quad (23)$$

$$C \leq \text{BAU} + \sum_g IG_g \cdot \text{MaxP}_g \cdot \text{CCD}_g \cdot An_g + \sum_{i \in c, k} (\text{FCC}_i \cdot Pur_i + \text{VCC}_i \cdot Cap_i + \text{VCSC}_k \cdot ECap_k) \cdot An_i - \frac{\sum_g IG_g \cdot \text{MaxP}_g \cdot \text{CC}_g + \sum_{i \in c, k} (\text{FCC}_i \cdot Pur_i + \text{VCC}_i \cdot Cap_i + \text{VCSC}_k \cdot ECap_k)}{\text{PBP}} \quad [\$] \quad (24)$$

$$RH_{j,m,d,h,u} = 0 \quad \forall j, m, d, h : u \notin S(j) \quad [\text{kW}] \quad (25)$$

$$UL_{m,d,h,u} = 0 \quad \forall m, d, h : u \in \{\text{sh, wh, ng}\} \quad [\text{kW}] \quad (26)$$

219

220 The objective function (1) consists of all key cost components, including utility charges, annualized capital
221 costs of DER investments, and operation and maintenance costs. The main optimization constraints are
222 expressed in (2) - (26):

- 223 • Eq. (2) - (5) force the energy balances for the different end-uses.
224 • The boundaries for the operation of distributed generation and storage technologies are set in
225 (6) - (11) and (12) - (19), respectively, where \mathbf{M} is an arbitrarily large number.

- 226 • The absorption chiller operation is described in (20).
- 227 • Simultaneous import and export of power are prevented in (21) and (22).
- 228 • The annuity factors are calculated in (23).
- 229 • Eq. (24) presents the payback constraint, in which investments must be repaid in a period shorter
- 230 than the payback period.
- 231 • Eq. (25) and (26) show the boundary conditions that ensure the proper links between different
- 232 technologies and loads.

233 **2.3. Changes to the formulation of DER-CAM**

234 **2.3.1. Overview**

235 The following section describes the changes made to the mathematical formulation of DER-CAM to
236 implement Ancillary Services (AS) market participation. It is important to keep in mind that AS markets
237 are currently available in distinct ISO service territories, and each market may have specific requirements
238 that differ from one another. Therefore, the formulation to support AS markets does not follow the rules
239 of any specific market, but instead is designed in a flexible way to support all the relevant features.

240 As discussed in [28], the key AS markets can be grouped in three categories, including Frequency
241 Regulation (Up and Down), Spinning Reserve, and Non-Spinning Reserve, all of which are considered in
242 the enhanced DER-CAM formulation. These markets may have different requirements throughout
243 different ISO territories, including how fast a unit must be able to respond to a service request upon a
244 successful bid, the minimum size of the resource in order to participate in the market, or the minimum
245 length of the bid duration. Typically, bids must hold for at least one hour in all AS markets, and response
246 to requests may be required within seconds (or automatic) for frequency regulation markets, or within a
247 few minutes, in the case of spinning and non-spinning reserve markets. For example, Non-Spinning
248 Reserves in the CAISO territory, in California, must be able to respond within 10 minutes of being called,
249 and must run for at least two hours, while the same service in the ERCOT territory, Texas, must respond
250 within 30 min and run for at least one hour. All changes made to DER-CAM take such requirements into
251 account.

252 **2.3.2. Key Assumptions**

253 Given the investment planning nature of DER-CAM, adding support to AS markets uses a deterministic
254 approach. Historic information on market clearing prices for different AS markets is used as reference,
255 under the general assumption that the microgrid under analysis is a price taker and the market clearing
256 price is a good indicator for a successful bid. Under this premise, the capacity allocation determined by
257 DER-CAM for participation in AS markets is always considered to be awarded.

258 The revenue resulting from each AS market bid is calculated based on the market clearing price and the
259 bid duration as selected by the model, provided all market requirements are met. It should be noted that
260 when successful, all bids in ISO markets are fully awarded, regardless of service requests.

261 Providing AS also creates an additional cost to the microgrid, as both additional fuel and O&M costs will
262 be incurred whenever a service is requested. Additionally, costs due to increases in demand charges may

263 also occur in the event of down-regulation requests, which can be severe if occurring during peak hours
 264 with high time-of-use rates. Other costs incurred by the microgrid as a result of AS provision include
 265 different opportunity costs, as the capacity allocation of a specific resource prevents its use for any other
 266 purpose. All of these are taken into account in the optimization.

267 Calculating the additional microgrid costs or benefits relies on the use of user-defined expectations on
 268 service provision. This is expressed in the formulation by an effective utilization ratio, α . In this initial
 269 implementation of AS products in DER-CAM all effective utilization ratios are assumed constant
 270 throughout the optimization window, although they can easily be expanded in future developments to
 271 model time-dependency of the service request expectation.

272 The addition of support to Spinning, Non-Spinning, and Regulation markets in DER-CAM led to several
 273 modifications to the existing formulation, including changes to operational constrains, and high-level
 274 balance equations. These changes are explained in detail below.

275 **2.3.3. Operational constrains**

276 Adding support for different AS markets requires, first and foremost, modifying the possible capacity
 277 allocations of each relevant resource. In prior formulations, all generation technologies could only provide
 278 power for either on-site consumption or export, and storage technologies could be used only for on-site
 279 arbitrage. After the modifications made to support Ancillary Services, both generator units and stationary
 280 storage can also provide spinning, non-spinning, up-regulation and down-regulation services.

281 In general, all dispatch equations for generators have been updated to include these services, as
 282 expressed below:

$$GU_{g,m,d,h,u} + GS_{g,m,d,h,u} + GRS_{g,m,d,h} + GRSNS_{g,m,d,h} + GRNS_{g,m,d,h} \quad [\text{kW}] \quad (27) \\ + GRU_{g,m,d,h} \leq \text{Max}P_g$$

283 Where:

284 $GRS_{g,m,d,h}$ capacity allocated for spinning reserve by online technology g , at time m, d, h [kW]

285 $GRNS_{g,m,d,h}$ capacity allocated for non-spinning reserve by offline technology g , at time m, d, h [kW]

286 $GRSNS_{g,m,d,h}$ capacity allocated for non-spinning reserve by online technology g , at time m, d, h [kW]

287 $GRU_{g,m,d,h}$ capacity allocated for up-regulation by online technology g , at time m, d, h [kW]

288 It should be noted that spinning units may typically also be used for non-spinning reserves, and for that
 289 reason the total reserve provided by spinning units was sub-divided into a component for spinning reserve
 290 and non-spinning reserve markets, as shown in Eq. (27). The resulting operational constraint now states
 291 that the overall capacity allocation, including on-site generation, power exports for traditional feed-in
 292 markets, and capacity allocated to ancillary service markets must not exceed the rated nameplate capacity
 293 of a given generation unit. Down-regulation is not included in this equation to prevent instances where
 294 call requests would lead to exceeding the unit capacity (for example symmetric up- and down-regulation
 295 hourly bids could keep the unit within operational boundaries, but requests occurring only to up-
 296 regulation would lead to an operational violation). Instead, the following additional constraints are added:

$$GU_{g,m,d,h} + GS_{g,m,d,h} - GRD_{g,m,d,h} \geq \text{Min}L_g \quad [\text{kW}] \quad (28)$$

$$GRD_{g,m,d,h} \leq \text{Max}P_g \cdot (1 - \text{Min}L_g) \quad [\text{kW}] \quad (29)$$

297 Where:

298 $GRD_{g,m,d,h}$ capacity allocated for down-regulation by online technology g , at time m , d , h [kW]

299 Additionally, the following equations were added to ensure that Non-Spinning reserve bids respect
300 minimum part-load requirements:

$$GRNS_{g,m,d,h} \geq \text{Min}L_g \cdot bAux_{g,m,d,h}, \quad bAux_{g,m,d,h} \in \{0,1\} \quad [\text{kW}] \quad (30)$$

$$GRNS_{b,m,d,h} \leq bAux_{g,m,d,h} \cdot \mathbf{M} \quad [\text{kW}] \quad (31)$$

301 Other key elements relevant for determining market participation of DG units include the time
302 requirements they must comply with in order to be eligible for bidding, either in its ability to start, TTSR,
303 or to ramp, TTRR. For this purpose, additional parameters were introduced in the description of DG units,
304 TTS_g and TTR_g , where users can specify how fast each unit can go online or ramp from the minimum
305 operating part-load to the rated nameplate capacity, respectively.

306 To understand this last parameter, it is important to keep in mind that DER-CAM is a mixed-integer linear
307 program, where all variable relations are described using linear functions. This implies the use of several
308 linearization procedures, which include fuel efficiency curves. In this particular case one of two methods
309 can be applied – a linear step-wise approximation [34], or a constant efficiency associated with a minimum
310 part-load requirement ($\text{Min}L_g$ in equation 7). For most standard DG units this minimum part-load
311 requirement is greater than or equal to 70% of the nameplate capacity, meaning that the TTR_g parameter
312 is used to describe the time to ramp from this minimum part-load value up to the nameplate capacity.

313 The parameters described above are used to exclude DG units that do not meet market requirements,
314 along with backup generators, which are equally excluded from bidding into AS markets, as shown in the
315 operational constraints below.

$$GRS_{g,m,d,h} = 0 : TTR_g > TTRR \cup \text{BackUpOnly}_g = 1 \quad [\text{kW}] \quad (32)$$

$$GRNS_{g,m,d,h} = 0 : TTS_g > TTSR \cup \text{BackUpOnly}_g = 1 \quad [\text{kW}] \quad (33)$$

316 Further to these requirements, AS markets often define minimum length for bid durations, as well as
317 minimum bid capacity. This is specific to each market, and requires the new set of operational constraints
318 introduced below. To achieve this purpose while preserving linearity additional binary variables were
319 added to track the change of status in the provision of ancillary services (enabled or disabled), and to force
320 service duration for a minimum number of θ time steps. These equations were implemented separately
321 for all four AS products.

322 Spinning Reserve

$$S_{m,d,h} \leq bS_{m,d,h} \cdot \mathbf{M}, \quad bS_{m,d,h} \in \{0,1\} \quad [\text{kW}] \quad (34)$$

$$SwS_{m,d,h} = bS_{m,d,h} - bS_{m,d,h-1} \quad [1] \quad (35)$$

$$\sum_{\hat{h}} bS_{m,d,\hat{h}} \geq SwS_{m,d,h} \cdot \theta, \quad \hat{h} = \{h, h+1, \dots, h+\theta\} \quad [1] \quad (36)$$

$$S_{m,d,h} \geq bS_{m,d,h} \cdot SMinBid \quad [kW] \quad (37)$$

323 Non-Spinning Reserve

$$NS_{m,d,h} \leq bNS_{m,d,h} \cdot \mathbf{M}, \quad bNS_{j,m,d,h} \in \{0,1\} \quad [kW] \quad (38)$$

$$SwNS_{m,d,h} = bNS_{j,m,d,h} - bNS_{j,m,d,h-1} \quad [1] \quad (39)$$

$$\sum_{\hat{h}} bNS_{m,d,\hat{h}} \geq SwNS_{m,d,h} \cdot \theta, \quad \hat{h} = \{h, h+1, \dots, h+\theta\} \quad [1] \quad (40)$$

$$NS_{m,d,h} \geq bNS_{j,m,d,h} \cdot NSMinBid \quad [kW] \quad (41)$$

324 Up-Regulation

$$RUp_{m,d,h} \leq bRUp_{m,d,h} \cdot \mathbf{M}, \quad bRUp_{m,d,h} \in \{0,1\} \quad [kW] \quad (42)$$

$$SwRUp_{m,d,h} = bRUp_{m,d,h} - bRUp_{m,d,h-1} \quad [1] \quad (43)$$

$$\sum_{\hat{h}} bRUp_{m,d,\hat{h}} \geq SwRUp_{m,d,h} \cdot \theta, \quad \hat{h} = \{h, h+1, \dots, h+\theta\} \quad [1] \quad (44)$$

$$RUp_{m,d,h} \geq bRUp_{m,d,h} \cdot RUpMinBid \quad [kW] \quad (45)$$

325 Down Regulation

$$RDn_{m,d,h} \leq bRDn_{m,d,h} \cdot \mathbf{M}, \quad bRDn_{m,d,h} \in \{0,1\} \quad [kW] \quad (46)$$

$$SwRDn_{m,d,h} = bRDn_{m,d,h} - bRDn_{m,d,h-1} \quad [1] \quad (47)$$

$$\sum_{\hat{h}} bRDn_{m,d,\hat{h}} \geq SwRDn_{m,d,h} \cdot \theta, \quad \hat{h} = \{h, h+1, \dots, h+\theta\} \quad [1] \quad (48)$$

$$RDn_{m,d,h} \geq bRDn_{m,d,h} \cdot RDnMinBid \quad [kW] \quad (49)$$

326

327 Where:

328 $S_{m,d,h}$ total spinning reserve bid, including generation and storage components, in time m, d, h [kW]

329 $bS_{m,d,h}$ binary spinning market participation decision [b]

330 $SwS_{m,d,h}$ change on the spinning reserve market participation decision [1]

331 $SMinBid$ minimum bid for spinning reserve market [kW]

332 $NS_{m,d,h}$ total non-spinning reserve bid, including generation and storage components, in time m, d, h [kW]

333 $bNS_{m,d,h}$ binary non-spinning market participation decision [b]

334 $SwNS_{m,d,h}$ change on the non-spinning reserve market participation decision [1]

335 $NSMinBid$ minimum bid for non-spinning reserve market [kW]

336 $RUp_{m,d,h}$ total up-regulation bid, including generation and storage components, in time m, d, h
 337 [kW]

338 $bRUp_{m,d,h}$ binary up-regulation market participation decision [b]

339 $SwRUp_{m,d,h}$ change on the up-regulation market participation decision [1]

340 $RUpMinBid$ minimum bid for up-regulation market [kW]

341 $RDn_{m,d,h}$ total up-regulation bid, including generation and storage components, in time m, d, h
 342 [kW]

343 $bRDn_{m,d,h}$ binary up-regulation market participation decision [b]

344 $SwRDn_{m,d,h}$ change on the up-regulation market participation decision [1]

345 $RDnMinBid$ minimum bid for up-regulation market [kW]

346 Regarding storage, the power input and output from conventional technologies has also been divided into
 347 multiple components, including power for onsite consumption, but also for spinning and non-spinning
 348 reserve, as well as up and down frequency regulation, as shown below.

$$SOut_{k,m,d,h} = \sum_u SOutSite_{k,m,d,h,u} + SOutRUp_{k,m,d,h} + SOutS_{k,m,d,h} + SOutNS_{k,m,d,h}, \quad k = \{ES\} \quad [kW] \quad (50)$$

$$SIn_{k,m,d,h} = SInSite_{k,m,d,h} + SInRDn_{k,m,d,h}, \quad k = \{ES\} \quad [kW] \quad (51)$$

349

350 $SOut_{k,m,d,h}$ total output of storage technology k, at time m, d, h [kW]

351 $SOutSite_{k,m,d,h}$ output of storage technology k, at time m, d, h, for end-use u [kW]

352 $SOutS_{k,m,d,h}$ capacity allocated for spinning reserve by storage technology k, at time m, d, h [kW]

353 $SOutNS_{k,m,d,h}$ capacity allocated for non-spinning reserve by storage technology k, at time m, d, h [kW]

354 $SInSite_{k,m,d,h}$ input from on-site to storage technology k, at time m, d, h [kW]

355 $SInRDn_{k,m,d,h}$ input to storage technology k, at time m, d, h, due to down-regulation [kW]

356 **2.3.4. High level balance equations**

357 The extension of DER-CAM to support AS products requires high-level power balance equations to
 358 guarantee each service is provided by the adequate technologies. Namely, spinning reserves can be
 359 provided by any spinning on-site generator and stationary batteries, non-spinning reserve can be provided
 360 both by spinning and non-spinning on-site generators and stationary batteries, and both up and down
 361 regulation can be provided by spinning on-site generators and stationary batteries, as shown in the
 362 equations below.

$$S_{m,d,h} = \sum_g GRS_{g,m,d,h} + SOutS_{m,d,h} \quad [kW] \quad (52)$$

$$NS_{m,d,h} = \sum_g (GRNS_{g,m,d,h} + GRSNS_{g,m,d,h}) + SOutNS_{m,d,h} \quad [\text{kW}] \quad (53)$$

$$RUp_{m,d,h} = \sum_g GRUp_{g,m,d,h} + SOutRUp_{m,d,h} \quad [\text{kW}] \quad (54)$$

$$RDn_{m,d,h} = \sum_g GRDn_{g,m,d,h} + SInRDn_{m,d,h} \quad [\text{kW}] \quad (55)$$

363 It should be noted that in this first implementation all discrete generation technologies are allowed to
 364 provide ancillary services, as well as stationary storage. Renewable technologies are currently not directly
 365 included, due to the greater uncertainty in their output. However, renewable generation technologies can
 366 still be used to charge stationary storage, and in that way participate indirectly in AS markets.

367 **2.3.5. AS Market revenues**

368 The expected revenue from spinning reserve provision is calculated assuming the market clearing price is
 369 applicable.

$$SRev = \sum_{m,d,h} S_{m,d,h} \cdot SMktP_{m,d,h} \quad [\text{\$}] \quad (56)$$

$$NSRev = \sum_{m,d,h} NSn_{m,d,h} \cdot NSMktP_{m,d,h} \quad [\text{\$}] \quad (57)$$

$$RUpRev = RUp_{m,d,h} \cdot RUpMktP_{m,d,h} \quad [\text{\$}] \quad (58)$$

$$RDnRev = RDn_{m,d,h} \cdot RDnMktP_{m,d,h} \quad [\text{\$}] \quad (59)$$

370

371 $SMktP_{m,d,h}$ market clearing price for spinning reserve ancillary service in time m, d, h [$\text{\$/kW}$]

372 $NSMktP_{m,d,h}$ market clearing price for non-spinning reserve ancillary service in time m, d, h [$\text{\$/kW}$]

373 $RUpMktP_{m,d,h}$ market clearing price for up-regulation ancillary service in time m, d, h [$\text{\$/kW}$]

374 $RDnMktP_{m,d,h}$ market clearing price for down-regulation ancillary service in time m, d, h [$\text{\$/kW}$]

375 **2.3.6. Added Costs**

376 The additional costs incurred by the microgrid include four different components: added capital cost from
 377 additional DER investment, added fuel consumption for generator units, added O&M costs for generator
 378 units, and opportunity costs due to capacity allocation for AS provision.

379 The added capital costs resulting from additional investments are taken into account by the existing
 380 formulation without requiring any changes, as the current objective function already considers all
 381 investments and the financial constraints ensure that any additional investments are only made if proven
 382 to be cost-effective.

383 Similarly, all opportunity costs are considered in the existing formulation. By finding the cost-optimal
 384 solution, the trade-off between on-site resource utilization and allocation for AS markets is determined
 385 endogenously, and no additional changes are necessary.

386 Additional fuel costs and O&M costs require updating the formulation, to reflect both the added fuel and
 387 use of the generation resource. These are then used to replace the fuel and O&M components of the
 388 objective function.

$$FCn_{m,d,h} = \sum_g (GU_{g,m,d,h} + GS_{g,m,d,h} + GRS_{g,m,d,h} \cdot \alpha_S \quad [\$] \quad (60)$$

$$+ (GRSNS_{g,m,d,h} + GRNS_{g,m,d,h}) \cdot \alpha_{NS} + GRUP_{g,m,d,h} \cdot \alpha_{RUP}$$

$$- GRDn_{g,m,d,h} \cdot \alpha_{RDn}) / \eta_g$$

$$OMVC_{g,m} = \sum_{d,h} (GU_{g,m,d,h} + GS_{g,m,d,h} + GRS_{g,m,d,h} \cdot \alpha_S \quad [\$] \quad (61)$$

$$+ (GRSNS_{g,m,d,h} + GRNS_{g,m,d,h}) \cdot \alpha_{NS} + GRUP_{g,m,d,h} \cdot \alpha_{RUP}$$

$$- GRDn_{g,m,d,h} \cdot \alpha_{RDn}) \cdot OMV_g$$

389

390 3. Case Study

391 3.1. General Remarks

392 The following section presents an analysis of selected cases to illustrate the potential impact of
 393 considering the revenue of AS market participation in the optimal sizing of DER. These cases focus on
 394 sample microgrid configurations, including both single-building and multi-building microgrids.

395 The selected cases include residential buildings, office buildings, hospitals, and hypothetical microgrids
 396 where residential, office, and hospital buildings are aggregated. Two separate models were created for
 397 each of these cases, so that two distinct ISO territories could be analyzed. The selected territories include
 398 the California Independent System Operator (CAISO) and PJM (East Coast), as both these locations depict
 399 distinct weather conditions, energy loads, tariffs, and AS market prices.

400 The procedure consisted of conducting three sets of runs per model, creating a total of 24 cases:

- 401 • Set one, base case: The initial set consists of reference runs to establish the business as usual
 402 scenario, i.e., determining the site-wide energy costs prior to any investment analysis.
- 403 • Set two, investment analysis without AS market: The second set consists of an investment
 404 optimization run, however, it does not consider participation in the AS market.
- 405 • Set three, investment analysis with AS market: The third set consists of an investment
 406 optimization run with the consideration of participation in the AS market.

407 **3.2. Data collection**

408 **3.2.1. Energy Loads**

409 The building energy load data used to create the DER-CAM models consisted of information found in
410 building load databases made available by the U.S. Department of Energy (DOE). These datasets contain
411 load profiles for commercial and residential buildings and are based on the DOE's commercial reference
412 building model and the Residential Energy Consumption Survey (RECS) [35].

413 The load profiles are based on meteorological data using the Typical Meteorological Year (TMY3) dataset,
414 and the buildings selected include two commercial buildings (a hospital and a medium sized office
415 building) and one standard residential building. Load data was collected for two locations in the United
416 States, namely San Francisco and Washington/Baltimore, as they are located in the CAISO and PJM
417 territory, respectively.

418 The summary of the electric loads (electricity-only plus cooling plus refrigeration) used in the DER-CAM
419 models created is presented below.

420 *Table 1 - Summary of the electric loads used in the DER-CAM runs*

421 **3.2.2. Market Information**

422 **Utility Tariffs**

423 The tariff information used in the creation of DER-CAM models relied on the built-in tariff database
424 available in DER-CAM. This database contains tariffs for multiple locations across the U.S, and in this case
425 study, two tariffs were selected from both Pacific Gas & Electric (PG&E) and Baltimore Gas & Electric
426 (BG&E), as presented below.

427 *Table 2- Summary of the PG&E tariff information used in the DER-CAM runs, less than 200kW peak*

428

429 *Table 3- Summary of the PG&E tariff information used in the DER-CAM runs, more than 500kW peak*

430

431 *Table 4- Summary of the BG&E tariff information used in the DER-CAM runs, less than 2 GWh consumption*

432

433 *Table 5- Summary of the BG&E tariff information used in the DER-CAM runs, large commercial customers*

434

435 **AS Market Information**

436 All Ancillary Service market prices used in the case study were based on hourly historic data from 2014,
437 and summarized below.

438 *Figure 1- CAISO average weekday spinning reserve market clearing prices [28]*

439 *Figure 2- CAISO average weekday non-spinning reserve market clearing prices [28]*

440 *Figure 3- CAISO average Up-Regulation market clearing prices [28]*

441 *Figure 4- CAISO average Down-Regulation market clearing prices [28]*

442

443 *Figure 5- PJM average weekday spinning reserve market clearing prices [28]*

444 *Figure 6- PJM average weekday non-spinning reserve market clearing prices [28]*

445 *Figure 7- PJM average weekday regulation market clearing prices [28]*

446 Analyzing the data presented in these figures, AS market clearing prices tend to be highly volatile, with
447 large variability being observed not only from hour to hour, but also throughout different months of the
448 year. Nonetheless, it can be observed that non-spinning reserve is consistently the lowest priced product,
449 and that PJM clearing prices tend to be higher than those observed in the same product for CAISO
450 markets. Additionally, prices found in CAISO tend to observe peak values around 16:00, suggesting system
451 wide peaks occur around that period.

452 **3.2.3. DER Information**

453 The set of DER technologies considered in the case study includes both conventional and renewable
454 generation technologies, as well as stationary storage.

455 Provided below are the techno-economic data used to describe all DER options considered in the DER-
456 CAM runs.

457 *Table 6 - Photovoltaic modules*

458 *Table 7- Stationary Storage Characteristics*

459 *Table 8 - Conventional generation units*

460

461 **3.3. Key Results**

462 **3.3.1. Results in the CAISO territory**

463 The key results obtained in the CAISO territory are summarized in Table and Table , where San Francisco
464 data was used. Table summarizes the results for both residential and office building models.

465 Analyzing the results shows that investments in PV generation is advised, with a small 19 kW PV system
466 being suggested in the residential building and a larger 157 kW system being advised in the Office building.
467 Each of these cases leads to a reduction in both costs and CO₂ emissions, with a cost reduction of roughly
468 15% in the residential building case and a more significant reduction of roughly 33% in the office building
469 case. However, it should be noted that the investment suggestions do not include any technology with
470 the ability to provide AS.

471 When analyzing the runs where AS was enabled, it is observed that the optimal solution did not change.
472 In other words, given the problem size and economics, adding DG units and / or storage with the ability
473 to provide AS was not economically feasible, resulting in no impact from the expansion of the DER-CAM
474 capabilities. Table summarizes the results obtained for both a hospital microgrid, and the hypothetical
475 microgrid resulting from the aggregation of the residential, office and hospital buildings.

476 In this case, both models show once again cost reductions when analyzing potential DER investments prior
477 to the introduction of potential revenue from AS markets. Results obtained for the Hospital building

478 suggest a 1075 kW PV system as well as a combined 900 kW generation capacity, of which 750 kW consist
479 of CHP-enabled generation, leading to an overall cost reduction of approximately 16% in total energy
480 costs. In the aggregate case, the cost-optimal system configuration is similar, although 1343 kW of PV are
481 suggested, and conventional generation capacity is slightly higher, with a combined 1MW installed
482 capacity, of which 750 consist of CHP. In this case, the cost reduction is roughly 17%.

483 *Table 9 – CAISO: Costs, emissions and investments for a residential building and a medium sized office*

484 *Table 10 – CAISO: Costs, emissions and investments for a hospital and aggregated for all buildings.*

485

486 When analyzing the results obtained in the expanded DER-CAM model it can be observed that introducing
487 the ability to participate in AS markets had an impact on optimal results both for the Hospital and
488 Aggregated model. In this case, cost reductions were of roughly 17% in the hospital case and 18% in the
489 aggregated model, suggesting a slightly better economic performance due to the participation in AS
490 markets. Specifically, AS market participation led to annual revenues of roughly \$3,600 in the hospital
491 model and of \$4,500 in the aggregated model. While these revenues have little impact in the overall
492 energy cost, it should be noted that the optimal DER capacity portfolio is changed due to the possibility
493 to participate in AS markets. Namely, both cases see a reduction in total installed capacity, with the
494 Hospital case showing an optimal PV capacity of roughly 1MW and 750 kW of CHP, and the Aggregated
495 model showing a suggested PV capacity of roughly 1.1MW and an identical 750 kW CHP system.

496 While the ability to participate in AS markets could lead to the belief that additional capacity would be
497 installed, it must be noted that the ability to participate in AS markets has an influence on capacity factors.
498 Specifically, and given the minimum load constrains, the results obtained with prior DER-CAM
499 formulations suggest that larger generation units are often not used as it is not economically feasible to
500 run them below the minimum load requirement, potentially leading to the investment in smaller and
501 more flexible units. By adding the ability to participate in AS markets, cases where running generation at
502 load levels above the minimum requirements where not cost effective may now become attractive, as
503 this is a requirement to participate in Spinning markets, i.e., the additional revenue obtained from
504 successful AS bids makes it economically viable to run larger units at load levels that were previously not
505 economic, resulting in a lower need to install additional capacity for load following. This can be observed
506 when analyzing Figure and Figure , where the same dispatch period is shown both for the simple
507 investment case and the investment case where AS are considered. The comparison of these dispatch
508 profiles indicates a higher utilization and capacity factor for DG units when participation in AS markets is
509 enabled.

510 *Figure 8 – CAISO Aggregate Model, Simple Investment Case*

511 *Figure 9 – CAISO Aggregate Model, Investment Case with AS*

512 **3.3.2. Results for the PJM territory**

513 The key results obtained for the PJM territory are summarized in Table and Table 1, where Baltimore data
514 has been used. Table summarizes the results in the residential building microgrid model, and the office
515 building model. Unlike the results obtained in the CAISO runs, no DER investments were suggested in
516 either the simple investment or AS-enabled investment runs. These results are justified by the different

517 utility tariffs in these different territories, which make DER investments for smaller sized systems not cost-
518 effective.

519 Table 1 summarizes the results obtained for both the hospital microgrid model, and the hypothetical
520 microgrid resulting from the aggregation of the residential, office and hospital buildings.

521 *Table 11 - Costs, emissions and investments for a residential building and a medium sized office.*

522

523 In this case, both models show cost reductions when analyzing potential DER investments prior to the
524 introduction of potential revenue from AS markets. Results obtained for the Hospital building suggest a
525 combined 1250 kW generation capacity from conventional units, of which 750 kW consist of CHP-enabled
526 generation, leading to an overall cost reduction of approximately 16% in total energy costs. In the
527 aggregate case, the cost-optimal system configuration is similar, although a very small amount of PV is
528 suggested, and conventional generation capacity is slightly higher, with a combined 1325 kW installed
529 capacity, of which 750 consist of CHP. In this case, the cost reduction is roughly 32%.

530 *Table 1 - Costs, emissions and investments for a hospital and aggregated for all buildings.*

531

532 When analyzing the results obtained in the expanded DER-CAM model it can be observed that introducing
533 the ability to participate in AS markets had a significant impact in optimal results both for the Hospital and
534 Aggregated model. In this case, cost reductions were of roughly 22% in the hospital case and 36% in the
535 aggregated model, suggesting a more significant increase in the economic performance due to the
536 participation in AS markets when compared with the results obtained in CAISO. Specifically, AS market
537 participation led to an annual revenue of roughly \$108,000 in the Hospital model and of \$102,000 in the
538 aggregated model, two orders of magnitude above the revenues estimated in CAISO.

539 *Figure 10 – PJM Hospital Model, Simple Investment Case*

540 Similarly to the results obtained in the CA region, these revenues also had an impact in the optimal DER
541 capacity portfolio. In this case, however, the Hospital model showed the same overall installed capacity
542 but lower CHP. This result is a direct reflection of the participation in AS markets, as part of the testing
543 setup included disabling participation of CHP units in AS markets. As results show, the additional revenue
544 from AS justifies replacing a CHP unit with a conventional generator, even considering the additional utility
545 purchase to meet on-site heating requirements.

546 In the Aggregate model, a similar occurrence was observed, although the overall installed capacity was
547 increased to 1565 kW, suggesting that in this case the economic returns have improved following the
548 participation in AS markets.

549 It should be noted that the PJM regulation market requires up- and down- regulation markets to be made
550 symmetrically, i.e., both bids must be of equal magnitude in opposite directions.

551 *Figure 11 – PJM Hospital Model, Investment Case with AS*

552 **3.4. Final Remarks**

553 The analysis of overall results indicates that participation in AS markets has little impact on the optimal
554 DER portfolio, i.e., in all runs performed with AS the set of technologies was unchanged when compared
555 to the results obtained without AS participation.

556 It was further observed that participation in AS markets may influence the overall installed capacity,
557 although the exact behavior is dependent on the market economics. In the runs performed in the CAISO
558 territory the added revenue from AS markets led to a slightly lower installed capacity as a result of
559 increased capacity factor, while in the PJM territory the opposite behavior was observed, highlighting the
560 strong differences in utility tariffs in both territories.

561 **4. Conclusion**

562 This paper contributes to the state-of-the-art in DER sizing models by expanding upon DER-CAM and
563 implementing support for different ancillary service products. This includes Spinning, Non-Spinning, Up-
564 Regulation, and Down-Regulation AS products, and all changes to the formulation were implemented in
565 a flexible way and allow support to different AS markets throughout different ISO territories.

566 Further to the description of the revised mathematical formulation, a case study was conducted
567 highlighting the impact of potential revenues from AS market participation in optimal DER selection for
568 microgrids. The demonstration case consisted of four potential microgrid configurations, including a
569 residential building, an office building, a hospital, and a hypothetical microgrid consisting of the
570 aggregation of a residential building, and office building, and a hospital. The analysis was made assuming
571 these microgrids were located both in San Francisco and Baltimore, and PG&E and BG&E tariffs were used,
572 as well as CAISO and PJM market clearing prices for all four AS products introduced.

573 Results suggest that revenues from AS markets have a variable impact in the overall site-wide energy
574 costs, with results depending widely on the site-specific tariffs and AS market prices, although even in
575 cases where little overall cost impact was observed results suggest that the optimal investment portfolio
576 may change in a disproportional way, as a result of higher capacity factors being observed in DER where
577 market participation is enabled. In such cases as the added revenue from AS participation enables
578 operation in load levels that would otherwise not be cost-effective.

579 From a broader perspective, the results obtained in this work suggest that, provided the appropriate
580 regulatory conditions are created, DER participation in AS markets may be a viable revenue stream to
581 influence both microgrid sizing and dispatch, and more importantly provide valuable services to support
582 grid operations. Some initial policy efforts to enable DER participation in AS markets are already
583 underway, namely in the CAISO territory, through the establishment of DER Providers (owner or operator
584 of a DER aggregation) as new market participants [36].

585 **5. Acknowledgment**

586 The authors gratefully thank Rima Oueid and Dan Ton, the Smart Grid R&D Program Manager at the US
587 Department of Energy, for their continuous support of DER-CAM. Furthermore, we want to thank Argonne
588 National Laboratory, especially Guenter Conzelmann for providing the historical AS data needed for our

589 work. James T. Reilly played an instrumental role in our AS DER-CAM work and we are very grateful for
590 his support advancing DER-CAM into the latest DER-CAM⁺ version which considers also AS features.
591 The Distributed Energy Resources Customer Adoption Model (DER-CAM) has been designed at Lawrence
592 Berkeley National Laboratory (LBNL). DER-CAM has been funded partly by the Office of Electricity Delivery
593 and Energy Reliability, Distributed Energy Program of the U.S. Department of Energy under Contract No.
594 DE-AC02-05CH11231.

595 6. References

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686

687 *Table 2- Summary of the electric loads used in the DER-CAM runs*

Case	San Francisco		Baltimore	
	Peak load (kW)	Total annual load (MWh)	Peak load (kW)	Total annual load (MWh)
Residential	45	180	30	120
Office	125	548	123	547
Hospital	1027	5646	986	5270
Aggregated	1147	6374	1101	5937

688

689 *Table 3- Summary of the PG&E tariff information used in the DER-CAM runs, less than 200kW peak*

PG&E - less than 200kW peak	Summer (June-September)		Winter (October-May)	
	electricity (US\$/kWh)	demand (US\$/kW)	electricity (US\$/kWh)	demand (US\$/kW)
non-coincident	-	-	-	-
on-peak	0.60974	-	-	-
mid-peak	0.28352	-	0.17883	-
off-peak	0.15605	-	0.14605	-
fixed (US\$/month)	9.8			

summer on-peak: 11:00 to 18:00 on weekdays

summer mid-peak: 08:00 to 11:00 and 18:00 to 22:00 on weekdays

summer off-peak: 00:00 to 08:00 and 22:00 to 24:00 on weekdays, 00:00 to 24:00 on weekends

winter on-peak: N/A

winter mid-peak: 08:00 to 22:00 on weekdays

winter off-peak: 00:00 to 08:00 and 22:00 to 24:00 on weekdays and 00:00 to 24:00 on weekends

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695 *Table 4- Summary of the PG&E tariff information used in the DER-CAM runs, more than 500kW peak*

PG&E - greater than 500kW peak	Summer (June-September)		Winter (October-May)	
	electricity (US\$/kWh)	demand (US\$/kW)	electricity (US\$/kWh)	demand (US\$/kW)
non-coincident	-	14.38	-	14.38
on-peak	0.16233	19.04		-
mid-peak	0.10893	4.42	0.10185	0.24
off-peak	0.07397	-	0.07797	-
fixed (US\$/month)	591.45			

summer on-peak: 11:00 to 18:00 on weekdays

summer mid-peak: 08:00 to 11:00 and 18:00 to 22:00 on weekdays

summer off-peak: 00:00 to 08:00 and 22:00 to 24:00 on weekdays, 00:00 to 24:00 on weekends

winter on-peak: N/A

winter mid-peak: 08:00 to 22:00 on weekdays

winter off-peak: 00:00 to 08:00 and 22:00 to 24:00 on weekdays and 00:00 to 24:00 on weekends

696

697 *Table 5- Summary of the BG&E tariff information used in the DER-CAM runs, less than 2 GWh consumption*

BG&E - Less than 2GWh	Summer (June-September)		Winter (October-May)	
	electricity (US\$/kWh)	demand (US\$/kW)	electricity (US\$/kWh)	demand (US\$/kW)
non-coincident	-	-	-	-
on-peak	0.13546	-	0.13546	-
mid-peak	0.11874	-	0.11874	-
off-peak	0.09859	-	0.09859	-
fixed (US\$/month)	17.5			

summer on-peak: 09:00 to 22:00 on weekdays

summer mid-peak: 06:00 to 10:00 and 21:00 to 23:00 on weekdays

summer off-peak: 00:00 to 06:00 and 23:00 to 24:00 on weekdays, 00:00 to 24:00 on weekends

winter on-peak: 07:00 to 12:00 and 16:00 to 21:00 on weekdays

winter mid-peak: 12:00 to 16:00 on weekdays

winter off-peak: 00:00 to 06:00 and 21:00 to 24:00 on weekdays and 00:00 to 24:00 on weekends

698

699 *Table 6- Summary of the BG&E tariff information used in the DER-CAM runs, large commercial customers*

BG&E – Large Commercial	Summer (June-September)		Winter (October-May)	
	electricity (US\$/kWh)	demand (US\$/kW)	electricity (US\$/kWh)	demand (US\$/kW)
non-coincident	-	3.54	-	3.54
on-peak	0.12170	2.46	0.08149	2.46
mid-peak	0.08696	-	-	-
off-peak	0.08149	-	0.08149	-
fixed (US\$/month)	88			

summer on-peak: 09:00 to 22:00 on weekdays

summer mid-peak: 06:00 to 10:00 and 21:00 to 23:00 on weekdays

summer off-peak: 00:00 to 06:00 and 23:00 to 24:00 on weekdays, 00:00 to 24:00 on weekends

winter on-peak: 07:00 to 12:00 and 16:00 to 21:00 on weekdays

winter mid-peak: 12:00 to 16:00 on weekdays

winter off-peak: 00:00 to 06:00 and 21:00 to 24:00 on weekdays and 00:00 to 24:00 on weekends

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701

702 *Table 7 - Photovoltaic modules*

PV technology	Bifacial HIT-Si
Installation cost (\$/kW)	3237
Lifetime (years)	30
Peak efficiency	15.29%

703

704

705 *Table 8- Stationary Storage Characteristics*

Battery technology	Li-ion
Battery cost (\$/kWh)	560

Lifetime (years)	5
Maximum charge rate	C/4
Maximum discharge rate	C/4
Charging efficiency	0.95
Discharging efficiency	0.95
Max. depth of discharge	80%

706

707 *Table 9 - Conventional generation units*

DG Units	maxp kW	lifetime yr	capcost \$/kW	OMVar \$/kWh	electr. eff. -	HPR -	NoX g/kWh	UpTime -	MinLoad -
ICE_RB_75	75	15	2230	0.024	0.26	0	0.0068	93%	70%
ICE_RB_250	250	15	2073	0.024	0.27	0	0.0068	93%	70%
ICE_LB_500	500	15	1814	0.021	0.33	0	0.0008	93%	70%
MT_65	65	15	2737	0.013	0.24	0	0.0001	95%	75%
MT_200	200	15	2678	0.016	0.27	0	0.0001	95%	75%
MT_250	250	15	2311	0.011	0.26	0	0.0001	95%	75%
MCFC_300	300	20	10000	0.045	0.43	0	0.0000	98%	100%
PAFC_400	400	20	7000	0.036	0.38	0	0.0000	98%	100%
ICE_RB_CHP- HW_75	75	15	2881	0.0255	0.26	2.00	0.0068	93%	70%
ICE_RB_CHP- HW_250	250	15	2614	0.025	0.27	1.83	0.0068	93%	70%
ICE_LB_CHP- HW_500	500	15	2309	0.0215	0.33	1.22	0.0008	93%	70%
ICE_LB_CHP- HW_750	750	20	2200	0.0215	0.35	1.16	0.0008	93%	70%
MT_CHP- HW_65	65	15	3220	0.0145	0.24	1.57	0.0001	95%	75%
MT_CHP- HW_200	200	15	3150	0.017	0.27	1.10	0.0001	95%	75%

DG Units	maxp kW	lifetime yr	capcost \$/kW	OMVar \$/kWh	electr. eff. -	HPR -	NoX g/kWh	UpTime -	MinLoad -
MT_CHP- HW_250	250	15	2719	0.012	0.26	1.20	0.0001	95%	75%
MCFC_CHP- HW_300	300	20	10300	0.046	0.43	0.47	0.0000	98%	100%
PAFC _HP- HW_400	400	20	7300	0.037	0.38	0.57	0.0000	98%	100%

ICE - Internal Combustion Engine, MT - Micro Turbine, MCFC - Molten Carbonate Fuel Cell

PAFC - Phosphoric Acid Fuel Cell

RB - Rich Burn, LB – Lean Burn, CHP - Combined Heat and Power, HW - Hot Water Applications

HPR – Heat-Power Ratio

708

709 *Table 10 – CAISO: Costs, emissions and investments for a residential building and a medium sized office*

Costs in US\$	Residential building			Medium sized office		
	Base case	Simple investment	With AS	Base case	Simple investment	With AS
Total Costs	37,429	32,320	32,320	143,679	96,724	96,724
Electricity Costs	27,322	18,200	18,200	139,013	58,536	58,536
Fuel costs	10,107	10,107	10,107	4,666	4,666	4,666
Ann. Cap. cost	0	3,956	3,956	0	33,050	33,050
O&M cost	0	56	56	0	471	471
AS Revenue	-	-	0	-	-	0
CO ₂ (kg)	115,614	98,656	98,656	324,263	175,606	175,606
PV (kW)	-	19	19	-	157	157
Total DG (kW)	-	-	-	-	-	-
CHP (kW)	-	-	-	-	-	-

710

711 *Table 11 – CAISO: Costs, emissions and investments for a hospital and aggregated for all buildings.*

Costs in US\$	Hospital	Aggregated system
---------------	----------	-------------------

	Base case	Simple investment	With AS	Base case	Simple investment	With AS
Total Costs	1,385,310	1,164,147	1,157,303	1,517,047	1,264,577	1,249,716
Electricity Costs	1,239,299	255,314	323,248	1,360,328	264,103	278,942
Fuel costs	146,011	379,486	363,445	156,719	391,958	410,706
Ann. Cap. cost	0	424,787	374,744	0	502,786	450,362
O&M cost	0	104,560	100,325	0	105,729	113,324
AS Revenue	-	-	3,618	-	-	4460
CO ₂ (kg)	5,533,957	3,668,595	3,712,145	5,973,834	2,175,789	3,986,516
PV (kW)	-	1075	999	-	1343	1111
Total DG (kW)	-	900	750	-	1000	1000
CHP (kW)	-	750	750	-	750	750

712

713 *Table 12 - Costs, emissions and investments for a residential building and a medium sized office.*

Costs in US\$	Residential building			Medium sized office		
	Base case	Simple investment	With AS	Base case	Simple investment	With AS
Total Costs	31,357	31,357	31,357	73,215	73,215	73,215
Electricity Costs	25,451	25,451	25,451	69,573	69,573	69,573
Fuel costs	5,906	5,906	5,906	3,642	3,642	3,642
Ann. Cap. cost	0	0	0	0	0	0
O&M cost	0	0	0	0	0	0
AS Revenue	-	-	0	-	-	-
CO ₂ (kg)	223,946	223,946	223,946	534,395	534,395	534,395
PV	-	-	-	-	-	-
Total DG	-	-	-	-	-	-
CHP	-	-	-	-	-	-

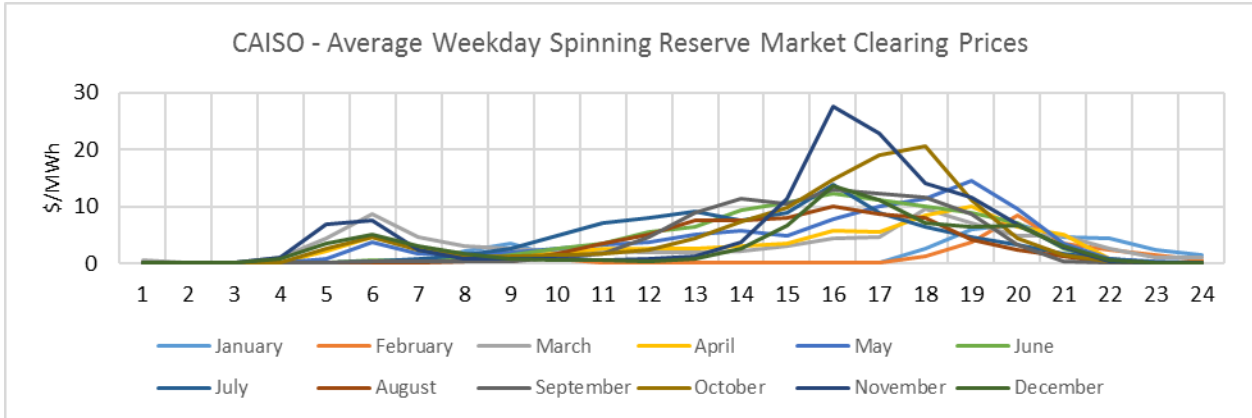
714

715 *Table 13 - Costs, emissions and investments for a hospital and aggregated for all buildings.*

Costs in US\$	Hospital			Aggregated system		
	Base case	Simple investment	With AS	Base case	Simple investment	With AS
Total Costs	1,001,780	837,859	782,605	1,343,417	919,607	856,020
Electricity Costs	9,45,984	73,175	130,433	1,281,700	23,308	34,380
Fuel costs	55,795	328,331	329,119	61,716	385,584	432,678
Ann. Cap. cost	0	275,645	301,883	0	331,310	370,779
O&M cost	0	159,433	129,760	0	170,051	120,892
AS Revenue	-	-	108,381	-	-	102,350
CO ₂ (kg)	8,492,950	6,199,267	6,703,209	9,251,291	6,876,192	7,768,291
PV	-	-	-	-	9	-
Total DG	-	1250	1250	-	1325	1565
CHP	-	750	500	-	750	500

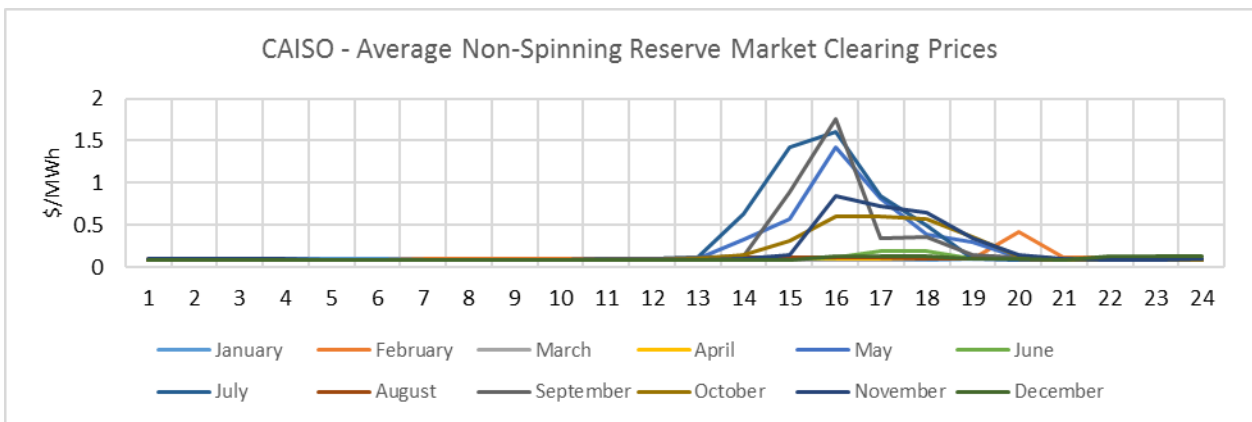
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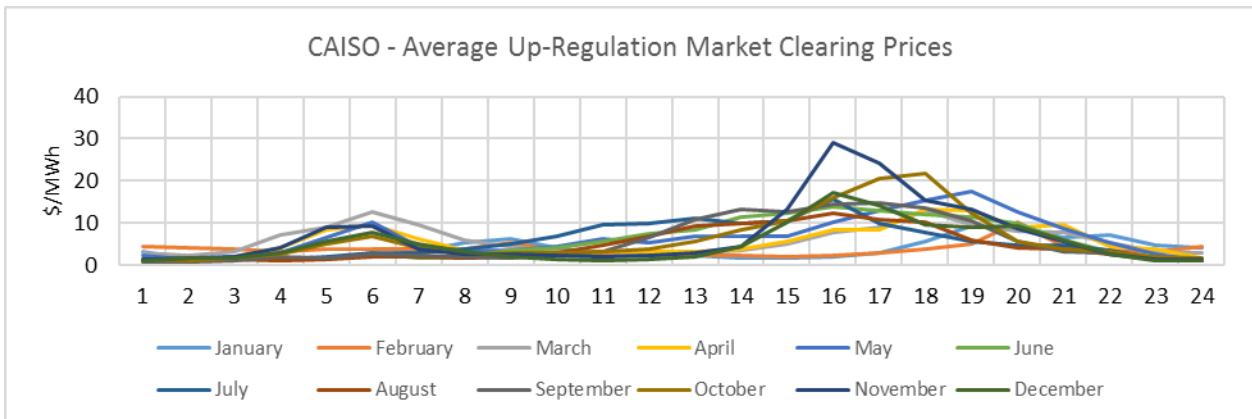
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719 Figure 1- CAISO average weekday spinning reserve market clearing prices [28]



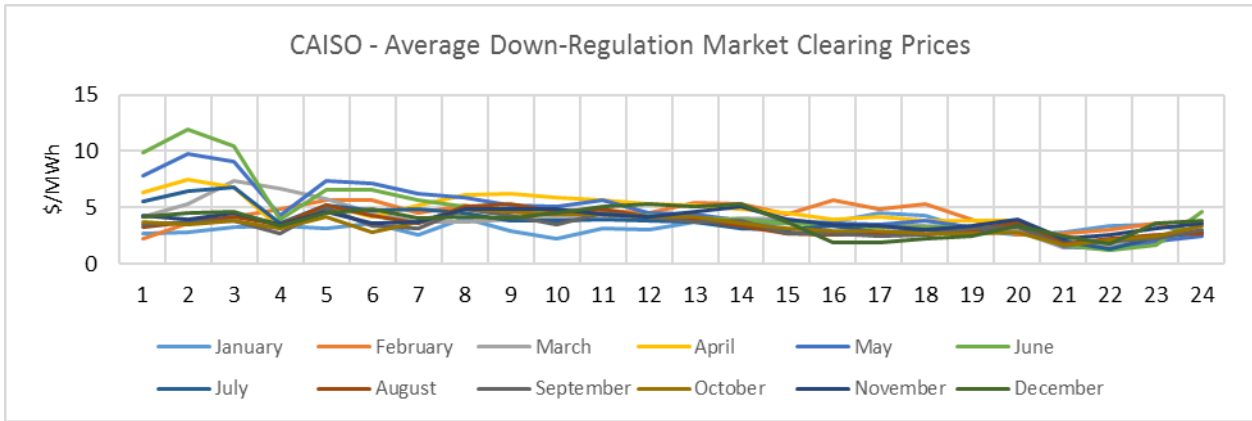
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721 Figure 2- CAISO average weekday non-spinning reserve market clearing prices [28]



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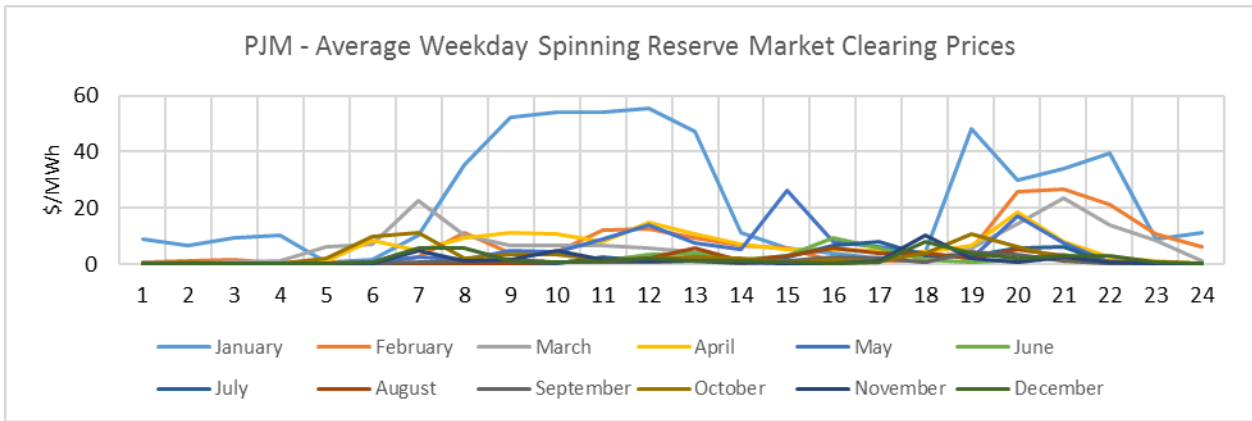
723 Figure 3- CAISO average Up-Regulation market clearing prices [28]



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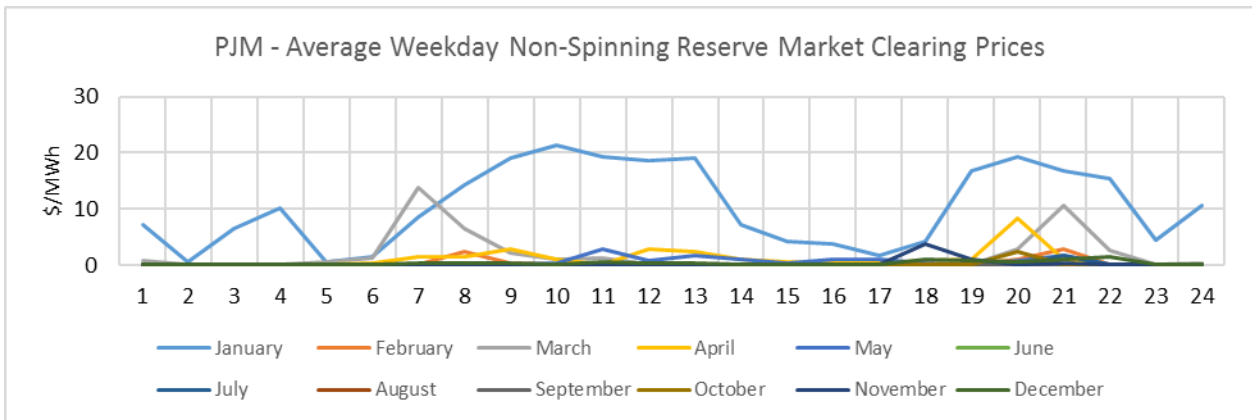
725 Figure 4- CAISO average Down-Regulation market clearing prices [28]

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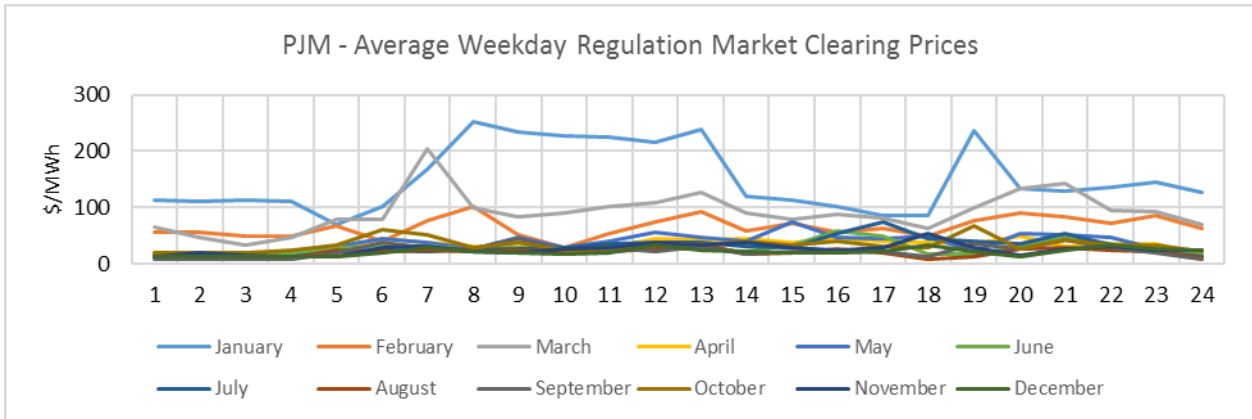
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728 Figure 5- PJM average weekday spinning reserve market clearing prices [28]



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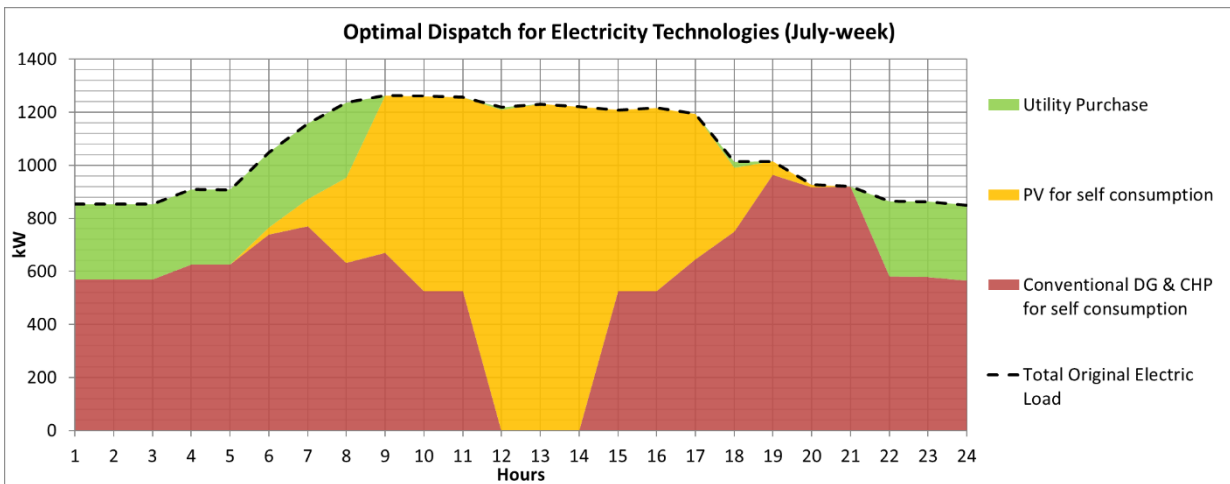
730 Figure 6- PJM average weekday non-spinning reserve market clearing prices [28]



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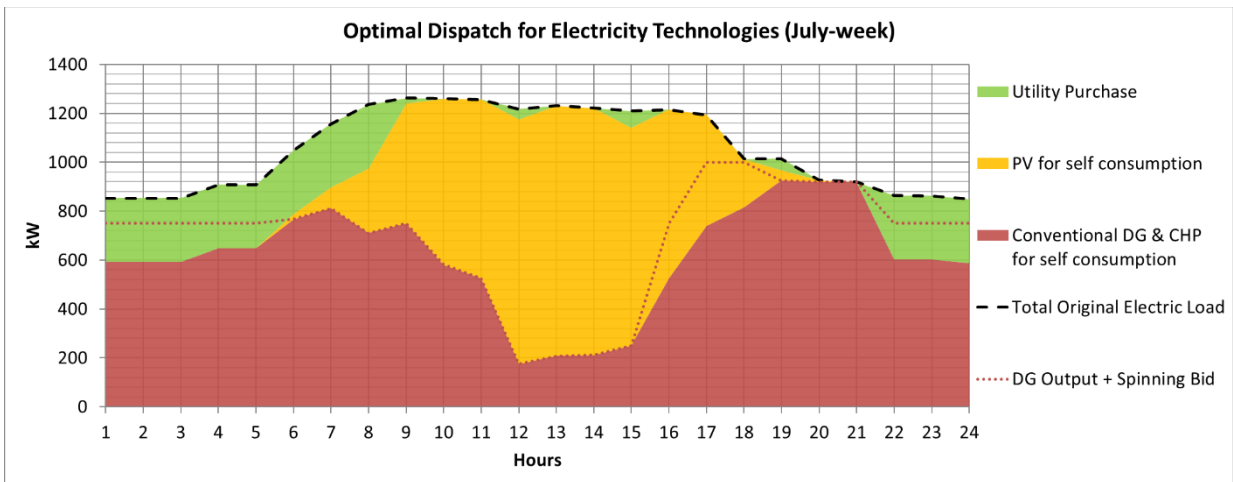
732 Figure 7- PJM average weekday regulation market clearing prices [28]

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735 Figure 8 – CAISO Aggregate Model, Simple Investment Case

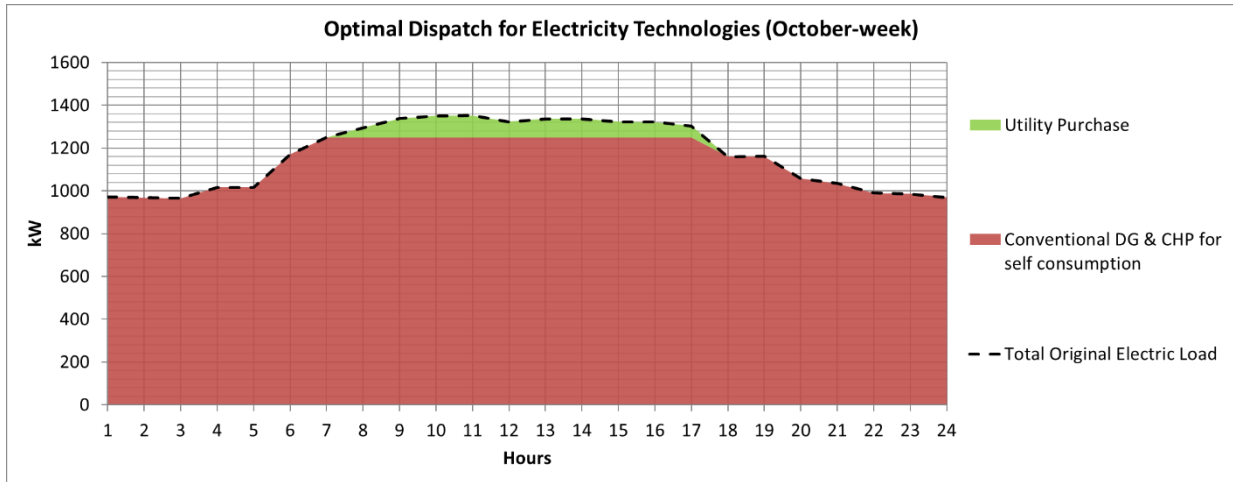


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737 Figure 9 – CAISO Aggregate Model, Investment Case with AS

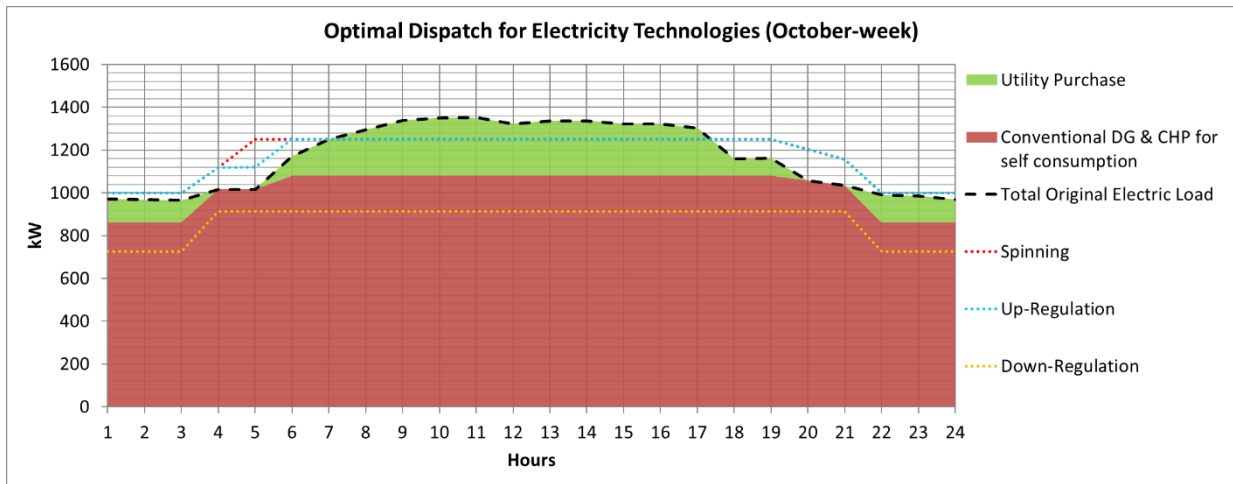
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740

741 *Figure 10 – PJM Hospital Model, Simple Investment Case*



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743 *Figure 11 – PJM Hospital Model, Investment Case with AS*

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