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Asset sizing with utility use constraints

Abstract

An energy optimization system includes an asset sizing system to determine an asset size and to cause a new asset to be purchased or installed. The energy optimization system uses a cost function dependent on a cost of operating a building system and on an initial purchase price of the new asset. The new asset may be a heat recover chiller, a solar energy system, a hydroelectric system, or an energy storage system. The optimization may be performed subject to a constraint related to the use of a resource supplied to the building system by one or more utilities. The optimization may include minimizing a simple pay back period or to maximizing a rate of return on the purchase of the new asset.

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Background/Summary

CROSS-REFERENCE TO RELATED PATENT APPLICATIONS (1) This application is a continuation of U.S. patent application Ser. No. 17/582,988, filed Jan. 24, 2022, which is a continuation of U.S. patent application Ser. No. 16/518,314, filed Jul. 22, 2019 (now U.S. Pat. No. 11,238,547), which is a continuation-in-part of U.S. patent application Ser. No. 15/426,962, filed Feb. 7, 2017 (now U.S. Pat. No. 10,359,748). U.S. patent application Ser. No. 16/518,314 is also a continuation-in-part of U.S. patent application Ser. No. 16/115,290, filed Aug. 28, 2018, which claims the benefit of and priority to U.S. Provisional Patent Application No. 62/558,135, filed Sep. 13, 2017. U.S. patent application Ser. No. 16/518,314 is also a continuation-in-part of U.S. patent application Ser. No. 16/352,485, filed Mar. 13, 2019 (now U.S. Pat. No. 10,909,642), which is a continuation of U.S. patent application Ser. No. 15/405,236, filed Jan. 12, 2017 (now U.S. Pat. No. 10,282,796). U.S. patent application Ser. No. 16/518,314 is also a continuation-in-part of U.S. patent application Ser. No. 16/383,228, filed Apr. 12, 2019 (now U.S. Pat. No. 11,036,249), which is a continuation of U.S. patent application Ser. No. 15/405,234, filed Jan. 12, 2017 (now U.S. Pat. No. 10,324,483). U.S. patent application Ser. No. 16/518,314 is also a continuation-in-part of U.S. patent application Ser. No. 15/616,616, filed Jun. 7, 2017 (now U.S. Pat. No. 10,949,777). The above-referenced patent applications are incorporated by reference herein in their entireties.

BACKGROUND

(1) The present disclosure relates generally to an energy cost optimization system for a building, a collection of buildings, or a central plant. The present disclosure relates more particularly to an energy cost optimization system that determines optimal asset sizes for various assets in the building, collection of buildings, or the central plant, as well as energy load setpoints for the assets.

(2) Assets in a building or central plant can include individual pieces of equipment or groups of equipment. For example, assets can include boilers, chillers, heat recovery chillers, steam generators, electrical generators, thermal energy storage tanks, batteries, air handling units, or other types of equipment in a building or a central plant. Assets can include collections of equipment which form a subplant of a central plant. For example, assets can include a heater subplant, a chiller subplant, a heat recovery chiller subplant, a steam subplant, and/or an electricity subplant. Some buildings or central plants include assets such as thermal energy storage (e.g., one or more cold thermal energy storage tanks) or electrical energy storage (e.g., one or more batteries).

(3) When purchasing an asset, a decision needs to be made regarding the best size of the asset for a given application. Asset purchase decisions are traditionally informed by various guidelines or rough approximations based on intended use. However, these guidelines and approximations are rarely optimal and can result in an asset purchase that is either insufficient or excessive for the given application. It can be difficult to determine the optimal sizes of assets in a building or central plant.

SUMMARY

(4) One implementation of the present disclosure is an energy cost optimization system for a building or campus. The system includes equipment operable to satisfy an energy load of the building or campus and a controller. The controller is configured to obtain a cost function defining a cost of operating the equipment over a time period as a function of one or more energy load setpoints for the equipment. The cost function includes a revenue term defining revenue to be obtained by operating the equipment to participate in an incentive program over the time period. The controller is also configured to modify the cost function to account for both an initial purchase cost of a new asset to be added to the equipment and an effect of the new asset on the cost of operating the equipment. Both the initial purchase cost of the new asset and the effect of the new asset on the cost of operating the equipment are functions of one or more asset size variables. The controller is also configured to perform an optimization of the modified cost function to determine values for the energy load setpoints, the asset size variables, and participation in the incentive program over the time period, and automatically initiate a process to acquire and install the new asset having an asset size based on the values of the asset size variables resulting from the optimization of the modified cost function.

(5) In some embodiments, the revenue term includes one or more of a demand response term or a frequency regulation term. In some embodiments, the cost function includes an equipment degradation term defining a cost of degradation of the equipment. In some embodiments, the cost function includes a maintenance cost term defining a cost of maintaining the equipment.

(6) In some embodiments, the cost function includes a peak load contribution term that defines a cost of purchasing an energy resource from a utility provider during peak load subperiods. The controller is configured modify the peak load contribution term by applying a peak subperiods vector to the peak load contribution term. The peak hours vector includes a prediction of which peak subperiods in the time period will be peak hours.

(7) In some embodiments, the controller is configured to perform the optimization of the modified cost function to determine values for the energy load setpoints following a stochastic optimization process. In some embodiments, the stochastic optimization process includes obtaining representative loads and rates for the building or campus for each of a plurality of scenarios and performing a first optimization to determine a peak demand target. The peak demand target minimizes a risk attribute of the cost function over the plurality of the scenarios. The method may include performing a second optimization subject to a constraint defined by the peak demand target to determine values for the energy load setpoints, the asset size variables, and participation in the incentive program over the time period.

(8) Another implementation of the present disclosure is a method. The method includes obtaining a cost function defining a cost operating building equipment over a time period as a function of one or more energy load setpoints for the equipment. The cost function includes a revenue term defining revenue to be obtained by operating the equipment to participate in an incentive program over the time period. The method includes modifying the cost function to account for both an initial purchase cost of a new asset to be added to the equipment and an effect of the new asset on the cost of operating the equipment, where both the initial purchase cost of the new asset and the effect of the new asset on the cost of operating the equipment are functions of one or more asset size variables. The method includes performing an optimization of the modified cost function to determine values for the energy load setpoints, the asset size variables, and participation in the incentive program over the time period, and initiating acquisition of the new asset having an asset size based on the values of the asset size variables resulting from the optimization of the modified cost function.

(9) In some embodiments, the revenue term includes one or more of a demand response term or a frequency regulation term. In some embodiments, the cost function includes an equipment degradation term defining a cost of degradation of the equipment. In some embodiments, the cost function includes a peak load contribution term defining a cost of purchasing an energy resource from a utility provider during peak load subperiods.

(10) In some embodiments, performing the optimization of the modified cost function includes performing a stochastic optimization process. The stochastic optimization process may include obtaining loads and rates for the building or campus for each of a plurality of scenarios, performing a first optimization to determine a peak demand target which minimizes a risk attribute of the cost function over the plurality of the scenarios, performing a second optimization subject to a constraint defined by the peak demand target to determine values for the energy load setpoints, the asset size variables, and participation in the incentive program over the time period. Performing the stochastic optimization process may include determining values of the asset size variables that minimize the cost function over a plurality of scenarios.

(11) In some embodiments, the method includes automatically scheduling an installation period for the new asset and controlling the building equipment to facilitate installation of the new asset during the installation period.

(12) Another implementation of the present disclosure is one or more non-transitory computer-readable media containing program instructions that, when executed by one or more processors, cause the one or more processors to perform operations. The operations include obtaining a cost function defining a cost operating building equipment over a time period as a function of one or more energy load setpoints for the equipment. The cost function includes a revenue term defining revenue to be obtained by operating the equipment to participate in an incentive program over the time period. The operations include modifying the cost function to account for both an initial purchase cost of a new asset to be added to the equipment and an effect of the new asset on the cost of operating the equipment, where both the initial purchase cost of the new asset and the effect of the new asset on the cost of operating the equipment are functions of one or more asset size variables. The operations include performing an optimization of the modified cost function to determine values for the energy load setpoints, the asset size variables, and participation in the incentive program over the time period, and initiating acquisition of the new asset having an asset size based on the values of the asset size variables resulting from the optimization of the modified cost function.

(13) In some embodiments, the revenue term includes one or more of a demand response term or a frequency regulation term. In some embodiments, the cost function includes one or more of an equipment degradation term defining a cost of degradation of the equipment or a maintenance cost term defining a cost of maintaining the equipment.

(14) Those skilled in the art will appreciate that the summary is illustrative only and is not intended to be in any way limiting. Other aspects, inventive features, and advantages of the devices and/or processes described herein, as defined solely by the claims, will become apparent in the detailed description set forth herein and taken in conjunction with the accompanying drawings.

Description

BRIEF DESCRIPTION OF THE DRAWINGS

(1) FIG. **1** is a block diagram of a frequency response optimization system, according to an exemplary embodiment.

(2) FIG. **2** is a graph of a regulation signal which may be provided to the system of FIG. **1** and a frequency response signal which may be generated by the system of FIG. **1**, according to an exemplary embodiment.

(3) FIG. **3** is a block diagram of a photovoltaic energy system configured to simultaneously perform both ramp rate control and frequency regulation while maintaining the state-of-charge of a battery within a desired range, according to an exemplary embodiment.

(4) FIG. **4** is a drawing illustrating the electric supply to an energy grid and electric demand from the energy grid which must be balanced in order to maintain the grid frequency, according to an exemplary embodiment.

(5) FIG. **5**A is a block diagram of an energy storage system including thermal energy storage and electrical energy storage, according to an exemplary embodiment.

(6) FIG. **5**B is a block diagram of an energy cost optimization system without thermal or electrical energy storage, according to an exemplary embodiment.

(7) FIG. **6**A is block diagram of an energy storage controller which may be used to operate the energy storage system of FIG. **5**A, according to an exemplary embodiment.

(8) FIG. **6**B is a block diagram of a controller which may be used to operate the energy cost optimization system of FIG. **5**B, according to an exemplary embodiment.

(9) FIG. **7** is a block diagram of a planning tool which can be used to determine the benefits of investing in a battery asset and calculate various financial metrics associated with the investment, according to an exemplary embodiment.

(10) FIG. **8** is a drawing illustrating the operation of the planning tool of FIG. **7**, according to an exemplary embodiment.

(11) FIG. **9** is a block diagram of a high level optimizer which can be implemented as a component of the controllers of FIGS. **6**A-**6**B or the planning tool of FIG. **7**, according to an exemplary embodiment.

(12) FIG. **10** is a block diagram illustrating the asset sizing module of FIG. **9** in greater detail, according to an exemplary embodiment.

(13) FIG. **11** is a graph illustrating an inverse relationship between an annuity factor and an interest rate for various values of a system life-cycle, according to an exemplary embodiment.

(14) FIG. **12** is a graph of the initial investment cost of an asset as a function of the annual benefit of the asset, according to an exemplary embodiment.

(15) FIG. **13** is another graph of the initial investment cost of an asset as a function of the annual benefit of the asset, according to an exemplary embodiment.

(16) FIG. **14** is another graph of the initial investment cost of an asset as a function of the annual benefit of the asset, according to an exemplary embodiment.

(17) FIG. **15** is another graph of the initial investment cost of an asset as a function of the annual benefit of the asset, according to an exemplary embodiment.

(18) FIG. **16** is a flowchart of a process for determining optimal asset sizes, according to an exemplary embodiment.

DETAILED DESCRIPTION

Overview

(19) Referring generally to the FIGURES, a building energy cost optimization system with asset sizing and components thereof are shown according to various exemplary embodiments. The systems and methods described herein can be configured to determine the optimal sizes of various assets in a building, group of buildings, or a central plant. Assets can include individual pieces of equipment (e.g., boilers, chillers, heat recovery chillers, steam generators, electrical generators, thermal energy storage tanks, batteries, etc.), groups of equipment, or entire subplants of a central plant. Asset sizes can include a maximum loading of the asset (e.g., maximum power, maximum charge/discharge rate) and/or a maximum capacity of the asset (e.g., maximum electric energy storage, maximum fluid storage, etc.).

(20) The energy cost optimization system can be configured to determine the optimal size of an asset by considering the potential benefits and costs of the asset. Potential benefits can include, for example, reduced energy costs, reduced demand charges, reduced peak load contribution (PLC) charges, and/or increased revenue from participating in incentive-based demand response (IBDR) programs such as frequency regulation (FR) or economic load demand response (ELDR). Potential costs can include fixed costs (e.g., an initial purchase cost of the asset) as well as marginal costs (e.g., ongoing costs of using the asset) over the time horizon. The potential benefits and costs of an asset may vary based on the application of the asset and/or the system in which the asset will be used. For example, a system that participates in FR programs may realize the benefit of increased IBDR revenue, whereas a system that does not participate in any IBDR programs may not realize such a benefit.

(21) Some of the benefits and costs of an asset may be captured by an original cost function J(x). For example, the cost function J(x) may include terms corresponding to energy cost, multiple demand charges, PLC charges, and/or IBDR revenue, as previously described. Adding one or more new assets may affect the values of some or all of these terms in the original cost function J(x). For example, adding a battery asset may increase IBDR revenue and decrease energy cost, demand charges, and PLC charges. However, the original cost function J(x) may not account for the fixed and marginal costs resulting from new asset purchases. In order to account for these fixed and marginal costs, asset sizing module **916** may add new terms to the original cost function J(x).

(22) The energy cost optimization system can be configured to augment the cost function J(x) with two new terms that correspond to the cost of purchasing the new assets, resulting in an augmented cost function J.sub.a(x). The additional terms are shown in the following equation:

J.sub.a(*x*)=*J*(*x*)+*c*.sub.f.sup.T*v*+*c*.sub.s.sup.T*s*.sub.a

where J(x) is the original cost function, x is the vector of decision variables of the optimization problem over the horizon, c.sub.f is a vector of fixed costs of buying any size of asset (e.g., one element for each potential asset purchase), v is a vector of binary decision variables that indicate whether the corresponding assets are purchased, c.sub.s is a vector of marginal costs per unit of asset size (e.g., cost per unit loading, cost per unit capacity), and s.sub.a is a vector of continuous decision variables corresponding to the asset sizes. Advantageously, the binary purchase decisions and asset size decisions are treated as decision variables which can be optimized along with the decision variables in the vector x. This allows the energy cost optimization system to perform a single optimization to determine optimal values for all of the decision variables in the augmented cost function J.sub.a(x), including the asset sizes.

(23) In some embodiments, the energy cost optimization system scales the asset purchase costs c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a to the duration of the optimization period h. The cost of purchasing an asset is typically paid over an entire payback period SPP, whereas the operational cost is only over the optimization period h. In order to scale the asset purchase costs to the optimization period, asset sizing module **916** can multiply the terms c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a by the ratio h/SPP as shown in the following equation:

(24) $J_a(x) = J(x) + \frac{h}{8760 \text{ .Math. SPP}}(c_f\, v + c_s^T s_a)$

where h is the duration of the optimization period in hours, SPP is the duration of the payback period in years, and 8760 is the number of hours in a year.

(25) The energy cost optimization system can perform an optimization process to determine the optimal values of each of the binary decision

variables in the vector v and each of the continuous decision variables in the vector s.sub.a. In some embodiments, the optimization system uses linear programming (LP) or mixed integer linear programming (MILP) to optimize a financial metric such as net present value (NPV), simple payback period (SPP), or internal rate of return (IRR). Each element of the vectors c.sub.f, v, c.sub.s, and s.sub.a may correspond to a particular asset and/or a particular asset size. Accordingly, the energy cost optimization system can determine the optimal assets to purchase and the optimal sizes to purchase by identifying the optimal values of the binary decision variables in the vector v and the continuous decision variables in the vector s.sub.a. These and other features of the energy cost optimization system are described in greater detail below.

(26) Frequency Response Optimization

(27) Referring now to FIG. **1**, a frequency response optimization system **100** is shown, according to an exemplary embodiment. System **100** is shown to include a campus **102** and an energy grid **104**. Campus **102** may include one or more buildings **116** that receive power from energy grid **104**. Buildings **116** may include equipment or devices that consume electricity during operation. For example, buildings **116** may include HVAC equipment, lighting equipment, security equipment, communications equipment, vending machines, computers, electronics, elevators, or other types of building equipment.

(28) In some embodiments, buildings **116** are served by a building management system (BMS). A BMS is, in general, a system of devices configured to control, monitor, and manage equipment in or around a building or building area. A BMS can include, for example, a HVAC system, a security system, a lighting system, a fire alerting system, and/or any other system that is capable of managing building functions or devices. An exemplary building management system which may be used to monitor and control buildings **116** is described in U.S. patent application Ser. No. 14/717,593 filed May 20, 2015, the entire disclosure of which is incorporated by reference herein.

(29) In some embodiments, campus **102** includes a central plant **118**. Central plant **118** may include one or more subplants that consume resources from utilities (e.g., water, natural gas, electricity, etc.) to satisfy the loads of buildings **116**. For example, central plant **118** may include a heater subplant, a heat recovery chiller subplant, a chiller subplant, a cooling tower subplant, a hot thermal energy storage (TES) subplant, and a cold thermal energy storage (TES) subplant, a steam subplant, and/or any other type of subplant configured to serve buildings **116**. The subplants may be configured to convert input resources (e.g., electricity, water, natural gas, etc.) into output resources (e.g., cold water, hot water, chilled air, heated air, etc.) that are provided to buildings **116**. An exemplary central plant which may be used to satisfy the loads of buildings **116** is described U.S. patent application Ser. No. 14/634,609 filed Feb. 27, 2015, the entire disclosure of which is incorporated by reference herein.

(30) In some embodiments, campus **102** includes energy generation **120**. Energy generation **120** may be configured to generate energy that can be used by buildings **116**, used by central plant **118**, and/or provided to energy grid **104**. In some embodiments, energy generation **120** generates electricity. For example, energy generation **120** may include an electric power plant, a photovoltaic energy field, or other types of systems or devices that generate electricity. The electricity generated by energy generation **120** can be used internally by campus **102** (e.g., by buildings **116** and/or central plant **118**) to decrease the amount of electric power that campus **102** receives from outside sources such as energy grid **104** or battery **108**. If the amount of electricity generated by energy generation **120** exceeds the electric power demand of campus **102**, the excess electric power can be provided to energy grid **104** or stored in battery **108**. The power output of campus **102** is shown in FIG. **1** as P.sub.campus. P.sub.campus may be positive if campus **102** is outputting electric power or negative if campus **102** is receiving electric power.

(31) Still referring to FIG. **1**, system **100** is shown to include a power inverter **106** and a battery **108**. Power inverter **106** may be configured to convert electric power between direct current (DC) and alternating current (AC). For example, battery **108** may be configured to store and output DC power, whereas energy grid **104** and campus **102** may be configured to consume and generate AC power. Power inverter **106** may be used to convert DC power from battery **108** into a sinusoidal AC output synchronized to the grid frequency of energy grid **104**. Power inverter **106** may also be used to convert AC power from campus **102** or energy grid **104** into DC power that can be stored in battery **108**. The power output of battery **108** is shown as P.sub.bat. P.sub.bat may be positive if battery **108** is providing power to power inverter **106** or negative if battery **108** is receiving power from power inverter **106**.

(32) In some embodiments, power inverter **106** receives a DC power output from battery **108** and converts the DC power output to an AC power output. The AC power output can be used to satisfy the energy load of campus **102** and/or can be provided to energy grid **104**. Power inverter **106** may synchronize the frequency of the AC power output with that of energy grid **104** (e.g., 50 Hz or 60 Hz) using a local oscillator and may limit the voltage of the AC power output to no higher than the grid voltage. In some embodiments, power inverter **106** is a resonant inverter that includes or uses LC circuits to remove the harmonics from a simple square wave in order to achieve a sine wave matching the frequency of energy grid **104**. In various embodiments, power inverter **106** may operate using high-frequency transformers, low-frequency transformers, or without transformers. Low-frequency transformers may convert the DC output from battery **108** directly to the AC output provided to energy grid **104**. High-frequency transformers may employ a multi-step process that involves converting the DC output to high-frequency AC, then back to DC, and then finally to the AC output provided to energy grid **104**.

(33) System **100** is shown to include a point of interconnection (POI) **110**. POI **110** is the point at which campus **102**, energy grid **104**, and power inverter **106** are electrically connected. The power supplied to POI **110** from power inverter **106** is shown as P.sub.sup. P.sub.sup may be defined as P.sub.bat+P.sub.loss, where P.sub.batt is the battery power and P.sub.loss is the power loss in the battery system (e.g., losses in power inverter **106** and/or battery **108**). P.sub.bat and P.sub.sup may be positive if power inverter **106** is providing power to POI **110** or negative if power inverter **106** is receiving power from POI **110**. P.sub.campus and P.sub.sup combine at POI **110** to form P.sub.POI. P.sub.POI may be defined as the power provided to energy grid **104** from POI **110**. P.sub.POI may be positive if POI **110** is providing power to energy grid **104** or negative if POI **110** is receiving power from energy grid **104**.

(34) Still referring to FIG. **1**, system **100** is shown to include a frequency response controller **112**. Controller **112** may be configured to generate and provide power setpoints to power inverter **106**. Power inverter **106** may use the power setpoints to control the amount of power P.sub.sup provided to POI **110** or drawn from POI **110**. For example, power inverter **106** may be configured to draw power from POI **110** and store the power in battery **108** in response to receiving a negative power setpoint from controller **112**. Conversely, power inverter **106** may be configured to draw power from battery **108** and provide the power to POI **110** in response to receiving a positive power setpoint from controller **112**. The magnitude of the power setpoint may define the amount of power P.sub.sup provided to or from power inverter **106**. Controller **112** may be configured to generate and provide power setpoints that optimize the value of operating system **100** over a time horizon.

(35) In some embodiments, frequency response controller **112** uses power inverter **106** and battery **108** to perform frequency regulation for energy grid **104**. Frequency regulation is the process of maintaining the stability of the grid frequency (e.g., 60 Hz in the United States). The grid frequency may remain stable and balanced as long as the total electric supply and demand of energy grid **104** are balanced. Any deviation from that balance may result in a deviation of the grid frequency from its desirable value. For example, an increase in demand may cause the grid frequency to decrease, whereas an increase in supply may cause the grid frequency to increase. Frequency response controller **112** may be configured to offset a fluctuation in the grid frequency by causing power inverter **106** to supply energy from battery **108** to energy grid **104** (e.g., to offset a decrease in grid frequency) or store energy from energy grid **104** in battery **108** (e.g., to offset an increase in grid frequency).

(36) In some embodiments, frequency response controller **112** uses power inverter **106** and battery **108** to perform load shifting for campus **102**. For example, controller **112** may cause power inverter **106** to store energy in battery **108** when energy prices are low and retrieve energy from battery **108** when energy prices are high in order to reduce the cost of electricity required to power campus **102**. Load shifting may also allow system **100** reduce the demand charge incurred. Demand charge is an additional charge imposed by some utility providers based on the maximum power consumption during an applicable demand charge period. For example, a demand charge rate may be specified in terms of dollars per unit of power (e.g., $/kW) and may be multiplied by the peak power usage (e.g., kW) during a demand charge period to calculate the demand charge. Load shifting may allow

system **100** to smooth momentary spikes in the electric demand of campus **102** by drawing energy from battery **108** in order to reduce peak power draw from energy grid **104**, thereby decreasing the demand charge incurred.

(37) Still referring to FIG. **1**, system **100** is shown to include an incentive provider **114**. Incentive provider **114** may be a utility (e.g., an electric utility), a regional transmission organization (RTO), an independent system operator (ISO), or any other entity that provides incentives for performing frequency regulation. For example, incentive provider **114** may provide system **100** with monetary incentives for participating in a frequency response program. In order to participate in the frequency response program, system **100** may maintain a reserve capacity of stored energy (e.g., in battery **108**) that can be provided to energy grid **104**. System **100** may also maintain the capacity to draw energy from energy grid **104** and store the energy in battery **108**. Reserving both of these capacities may be accomplished by managing the state-of-charge of battery **108**.

(38) Frequency response controller **112** may provide incentive provider **114** with a price bid and a capability bid. The price bid may include a price per unit power (e.g., $/MW) for reserving or storing power that allows system **100** to participate in a frequency response program offered by incentive provider **114**. The price per unit power bid by frequency response controller **112** is referred to herein as the "capability price." The price bid may also include a price for actual performance, referred to herein as the "performance price." The capability bid may define an amount of power (e.g., MW) that system **100** will reserve or store in battery **108** to perform frequency response, referred to herein as the "capability bid."

(39) Incentive provider **114** may provide frequency response controller **112** with a capability clearing price CP.sub.cap, a performance clearing price CP.sub.perf, and a regulation award Reg.sub.award, which correspond to the capability price, the performance price, and the capability bid, respectively. In some embodiments, CP.sub.cap, CP.sub.perf, and Reg.sub.award are the same as the corresponding bids placed by controller **112**. In other embodiments, CP.sub.cap, CP.sub.perf, and Reg.sub.award may not be the same as the bids placed by controller **112**. For example, CP.sub.cap, CP.sub.perf, and Reg.sub.award may be generated by incentive provider **114** based on bids received from multiple participants in the frequency response program. Controller **112** may use CP.sub.cap, CP.sub.perf, and Reg.sub.award to perform frequency regulation.

(40) Frequency response controller **112** is shown receiving a regulation signal from incentive provider **114**. The regulation signal may specify a portion of the regulation award Reg.sub.award that frequency response controller **112** is to add or remove from energy grid **104**. In some embodiments, the regulation signal is a normalized signal (e.g., between −1 and 1) specifying a proportion of Reg.sub.award. Positive values of the regulation signal may indicate an amount of power to add to energy grid **104**, whereas negative values of the regulation signal may indicate an amount of power to remove from energy grid **104**.

(41) Frequency response controller **112** may respond to the regulation signal by generating an optimal power setpoint for power inverter **106**. The optimal power setpoint may take into account both the potential revenue from participating in the frequency response program and the costs of participation. Costs of participation may include, for example, a monetized cost of battery degradation as well as the energy and demand charges that will be incurred. The optimization may be performed using sequential quadratic programming, dynamic programming, or any other optimization technique.

(42) In some embodiments, controller **112** uses a battery life model to quantify and monetize battery degradation as a function of the power setpoints provided to power inverter **106**. Advantageously, the battery life model allows controller **112** to perform an optimization that weighs the revenue generation potential of participating in the frequency response program against the cost of battery degradation and other costs of participation (e.g., less battery power available for campus **102**, increased electricity costs, etc.). An exemplary regulation signal and power response are described in greater detail with reference to FIG. **2**.

(43) Referring now to FIG. **2**, a pair of frequency response graphs **200** and **250** are shown, according to an exemplary embodiment. Graph **200** illustrates a regulation signal Reg.sub.signal **202** as a function of time. Reg.sub.signal **202** is shown as a normalized signal ranging from −1 to 1 (i.e., −1≤Reg.sub.signal≤1). Reg.sub.signal **202** may be generated by incentive provider **114** and provided to frequency response controller **112**. Reg.sub.signal **202** may define a proportion of the regulation award Reg.sub.award **254** that controller **112** is to add or remove from energy grid **104**, relative to a baseline value referred to as the midpoint b **256**. For example, if the value of Reg.sub.award **254** is 10 MW, a regulation signal value of 0.5 (i.e., Reg.sub.signal=0.5) may indicate that system **100** is requested to add 5 MW of power at POI **110** relative to midpoint b (e.g., P*.sub.POI=10 MW×0.5+b), whereas a regulation signal value of −0.3 may indicate that system **100** is requested to remove 3 MW of power from POI **110** relative to midpoint b (e.g., P*.sub.POI=10 MW×−0.3+b).

(44) Graph **250** illustrates the desired interconnection power P*.sub.POI **252** as a function of time. P*.sub.POI **252** may be calculated by frequency response controller **112** based on Reg.sub.signal **202**, Reg.sub.award **254**, and a midpoint b **256**. For example, controller **112** may calculate P*.sub.POI **252** using the following equation:

$$P^{*}.\text{sub.POI}=Reg.\text{sub.award}\times Reg.\text{sub.signal}+b$$

where P*.sub.POI represents the desired power at POI **110** (e.g., P*.sub.POI=P.sub.sup+P.sub.campus) and b is the midpoint. Midpoint b may be defined (e.g., set or optimized) by controller **112** and may represent the midpoint of regulation around which the load is modified in response to Reg.sub.signal **202**. Optimal adjustment of midpoint b may allow controller **112** to actively participate in the frequency response market while also taking into account the energy and demand charge that will be incurred.

(45) In order to participate in the frequency response market, controller **112** may perform several tasks. Controller **112** may generate a price bid (e.g., $/MW) that includes the capability price and the performance price. In some embodiments, controller **112** sends the price bid to incentive provider **114** at approximately 15:30 each day and the price bid remains in effect for the entirety of the next day. Prior to beginning a frequency response period, controller **112** may generate the capability bid (e.g., MW) and send the capability bid to incentive provider **114**. In some embodiments, controller **112** generates and sends the capability bid to incentive provider **114** approximately 1.5 hours before a frequency response period begins. In an exemplary embodiment, each frequency response period has a duration of one hour; however, it is contemplated that frequency response periods may have any duration.

(46) At the start of each frequency response period, controller **112** may generate the midpoint b around which controller **112** plans to perform frequency regulation. In some embodiments, controller **112** generates a midpoint b that will maintain battery **108** at a constant state-of-charge (SOC) (i.e. a midpoint that will result in battery **108** having the same SOC at the beginning and end of the frequency response period). In other embodiments, controller **112** generates midpoint b using an optimization procedure that allows the SOC of battery **108** to have different values at the beginning and end of the frequency response period. For example, controller **112** may use the SOC of battery **108** as a constrained variable that depends on midpoint b in order to optimize a value function that takes into account frequency response revenue, energy costs, and the cost of battery degradation. Exemplary techniques for calculating and/or optimizing midpoint b under both the constant SOC scenario and the variable SOC scenario are described in detail in U.S. patent application Ser. No. 15/247,883 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,885 filed Aug. 25, 2016, and U.S. patent application Ser. No. 15/247,886 filed Aug. 25, 2016. The entire disclosure of each of these patent applications is incorporated by reference herein.

(47) During each frequency response period, controller **112** may periodically generate a power setpoint for power inverter **106**. For example, controller **112** may generate a power setpoint for each time step in the frequency response period. In some embodiments, controller **112** generates the power setpoints using the equation:

$$P^{*}.\text{sub.POI}=Reg.\text{sub.award}\times Reg.\text{sub.signal}+b$$

where P*.sub.POI=P.sub.sup+P.sub.campus. Positive values of P*.sub.POI indicate energy flow from POI **110** to energy grid **104**. Positive values of P.sub.sup and P.sub.campus indicate energy flow to POI **110** from power inverter **106** and campus **102**, respectively.

(48) In other embodiments, controller **112** generates the power setpoints using the equation:

$$P^{*}.\text{sub.POI}=Reg.\text{sub.award}\times Res.\text{sub.FR}+b$$

where Res.sub.FR is an optimal frequency response generated by optimizing a value function. Controller **112** may subtract P.sub.campus from P*.sub.POI to generate the power setpoint for power inverter **106** (i.e., P.sub.sup=P*.sub.POI−P.sub.campus). The power setpoint for power inverter **106** indicates the amount of power that power inverter **106** is to add to POI **110** (if the power setpoint is positive) or remove from POI **110** (if the power setpoint is negative). Exemplary techniques which can be used by controller **112** to calculate power inverter setpoints are described in detail in U.S. patent application Ser. No. 15/247,793 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,784 filed Aug. 25, 2016, and U.S. patent application Ser. No. 15/247,777 filed Aug. 25, 2016. The entire disclosure of each of these patent applications is incorporated by reference herein.

Photovoltaic Energy System With Frequency Regulation and Ramp Rate Control

(49) Referring now to FIGS. **3**-**4**, a photovoltaic energy system **300** that uses battery storage to simultaneously perform both ramp rate control and frequency regulation is shown, according to an exemplary embodiment. Ramp rate control is the process of offsetting ramp rates (i.e., increases or decreases in the power output of an energy system such as a photovoltaic energy system) that fall outside of compliance limits determined by the electric power authority overseeing the energy grid. Ramp rate control typically requires the use of an energy source that allows for offsetting ramp rates by either supplying additional power to the grid or consuming more power from the grid. In some instances, a facility is penalized for failing to comply with ramp rate requirements.

(50) Frequency regulation is the process of maintaining the stability of the grid frequency (e.g., 60 Hz in the United States). As shown in FIG. **4**, the grid frequency may remain balanced at 60 Hz as long as there is a balance between the demand from the energy grid and the supply to the energy grid. An increase in demand yields a decrease in grid frequency, whereas an increase in supply yields an increase in grid frequency. During a fluctuation of the grid frequency, system **300** may offset the fluctuation by either drawing more energy from the energy grid (e.g., if the grid frequency is too high) or by providing energy to the energy grid (e.g., if the grid frequency is too low). Advantageously, system **300** may use battery storage in combination with photovoltaic power to perform frequency regulation while simultaneously complying with ramp rate requirements and maintaining the state-of-charge of the battery storage within a predetermined desirable range.

(51) Referring particularly to FIG. **3**, system **300** is shown to include a photovoltaic (PV) field **302**, a PV field power inverter **304**, a battery **306**, a battery power inverter **308**, a point of interconnection (POI) **310**, and an energy grid **312**. PV field **302** may include a collection of photovoltaic cells. The photovoltaic cells are configured to convert solar energy (i.e., sunlight) into electricity using a photovoltaic material such as monocrystalline silicon, polycrystalline silicon, amorphous silicon, cadmium telluride, copper indium gallium selenide/sulfide, or other materials that exhibit the photovoltaic effect. In some embodiments, the photovoltaic cells are contained within packaged assemblies that form solar panels. Each solar panel may include a plurality of linked photovoltaic cells. The solar panels may combine to form a photovoltaic array.

(52) PV field **302** may have any of a variety of sizes and/or locations. In some embodiments, PV field **302** is part of a large-scale photovoltaic power station (e.g., a solar park or farm) capable of providing an energy supply to a large number of consumers. When implemented as part of a large-scale system, PV field **302** may cover multiple hectares and may have power outputs of tens or hundreds of megawatts. In other embodiments, PV field **302** may cover a smaller area and may have a relatively lesser power output (e.g., between one and ten megawatts, less than one megawatt, etc.). For example, PV field **302** may be part of a rooftop-mounted system capable of providing enough electricity to power a single home or building. It is contemplated that PV field **302** may have any size, scale, and/or power output, as may be desirable in different implementations.

(53) PV field **302** may generate a direct current (DC) output that depends on the intensity and/or directness of the sunlight to which the solar panels are exposed. The directness of the sunlight may depend on the angle of incidence of the sunlight relative to the surfaces of the solar panels. The intensity of the sunlight may be affected by a variety of environmental factors such as the time of day (e.g., sunrises and sunsets) and weather variables such as clouds that cast shadows upon PV field **302**. When PV field **302** is partially or completely covered by shadow, the power output of PV field **302** (i.e., PV field power P.sub.PV) may drop as a result of the decrease in solar intensity.

(54) In some embodiments, PV field **302** is configured to maximize solar energy collection. For example, PV field **302** may include a solar tracker (e.g., a GPS tracker, a sunlight sensor, etc.) that adjusts the angle of the solar panels so that the solar panels are aimed directly at the sun throughout the day. The solar tracker may allow the solar panels to receive direct sunlight for a greater portion of the day and may increase the total amount of power produced by PV field **302**. In some embodiments, PV field **302** includes a collection of mirrors, lenses, or solar concentrators configured to direct and/or concentrate sunlight on the solar panels. The energy generated by PV field **302** may be stored in battery **306** or provided to energy grid **312**.

(55) Still referring to FIG. **3**, system **300** is shown to include a PV field power inverter **304**. Power inverter **304** may be configured to convert the DC output of PV field **302** P.sub.PV into an alternating current (AC) output that can be fed into energy grid **312** or used by a local (e.g., off-grid) electrical network. For example, power inverter **304** may be a solar inverter or grid-tie inverter configured to convert the DC output from PV field **302** into a sinusoidal AC output synchronized to the grid frequency of energy grid **312**. In some embodiments, power inverter **304** receives a cumulative DC output from PV field **302**. For example, power inverter **304** may be a string inverter or a central inverter. In other embodiments, power inverter **304** may include a collection of micro-inverters connected to each solar panel or solar cell. PV field power inverter **304** may convert the DC power output P.sub.PV into an AC power output u.sub.PV and provide the AC power output u.sub.PV to POI **310**.

(56) Power inverter **304** may receive the DC power output P.sub.PV from PV field **302** and convert the DC power output to an AC power output that can be fed into energy grid **312**. Power inverter **304** may synchronize the frequency of the AC power output with that of energy grid **312** (e.g., 50 Hz or 60 Hz) using a local oscillator and may limit the voltage of the AC power output to no higher than the grid voltage. In some embodiments, power inverter **304** is a resonant inverter that includes or uses LC circuits to remove the harmonics from a simple square wave in order to achieve a sine wave matching the frequency of energy grid **312**. In various embodiments, power inverter **304** may operate using high-frequency transformers, low-frequency transformers, or without transformers. Low-frequency transformers may convert the DC output from PV field **302** directly to the AC output provided to energy grid **312**. High-frequency transformers may employ a multi-step process that involves converting the DC output to high-frequency AC, then back to DC, and then finally to the AC output provided to energy grid **312**.

(57) Power inverter **304** may be configured to perform maximum power point tracking and/or anti-islanding. Maximum power point tracking may allow power inverter **304** to produce the maximum possible AC power from PV field **302**. For example, power inverter **304** may sample the DC power output from PV field **302** and apply a variable resistance to find the optimum maximum power point. Anti-islanding is a protection mechanism that immediately shuts down power inverter **304** (i.e., preventing power inverter **304** from generating AC power) when the connection to an electricity-consuming load no longer exists. In some embodiments, PV field power inverter **304** performs ramp rate control by limiting the power generated by PV field **302**.

(58) Still referring to FIG. **3**, system **300** is shown to include a battery power inverter **308**. Battery power inverter **308** may be configured to draw a DC power P.sub.bat from battery **306**, convert the DC power P.sub.bat into an AC power u.sub.bat, and provide the AC power u.sub.bat to POI **310**. Battery power inverter **308** may also be configured to draw the AC power u.sub.bat from POI **310**, convert the AC power u.sub.bat into a DC battery power P.sub.bat, and store the DC battery power P.sub.bat in battery **306**. The DC battery power P.sub.bat may be positive if battery **306** is providing power to battery power inverter **308** (i.e., if battery **306** is discharging) or negative if battery **306** is receiving power from battery power inverter **308** (i.e., if battery **306** is charging). Similarly, the AC battery power u.sub.bat may be positive if battery power inverter **308** is providing power to POI **310** or negative if battery power inverter **308** is receiving power from POI **310**.

(59) The AC battery power u.sub.bat is shown to include an amount of power used for frequency regulation (i.e., u.sub.FR) and an amount of power used for ramp rate control (i.e., u.sub.RR) which together form the AC battery power (i.e., u.sub.bat=u.sub.FR+u.sub.RR). The DC battery power P.sub.bat is shown to include both u.sub.FR and u.sub.RR as well as an additional term P.sub.loss representing power losses in battery **306** and/or battery power inverter **308** (i.e., P.sub.bat=u.sub.FR+u.sub.RR+P.sub.loss). The PV field power u.sub.PV and the battery power u.sub.bat combine at

POI **110** to form P.sub.POI (i.e., P.sub.POI=u.sub.PV+u.sub.bat), which represents the amount of power provided to energy grid **312**. P.sub.POI may be positive if POI **310** is providing power to energy grid **312** or negative if POI **310** is receiving power from energy grid **312**.

(60) Still referring to FIG. **3**, system **300** is shown to include a controller **314**. Controller **314** may be configured to generate a PV power setpoint u.sub.PV for PV field power inverter **304** and a battery power setpoint u.sub.bat for battery power inverter **308**. Throughout this disclosure, the variable u.sub.PV is used to refer to both the PV power setpoint generated by controller **314** and the AC power output of PV field power inverter **304** since both quantities have the same value. Similarly, the variable u.sub.bat is used to refer to both the battery power setpoint generated by controller **314** and the AC power output/input of battery power inverter **308** since both quantities have the same value.

(61) PV field power inverter **304** uses the PV power setpoint u.sub.PV to control an amount of the PV field power P.sub.PV to provide to POI **110**. The magnitude of u.sub.PV may be the same as the magnitude of P.sub.PV or less than the magnitude of P.sub.PV. For example, u.sub.PV may be the same as P.sub.PV if controller **314** determines that PV field power inverter **304** is to provide all of the photovoltaic power P.sub.PV to POI **310**. However, u.sub.PV may be less than P.sub.PV if controller **314** determines that PV field power inverter **304** is to provide less than all of the photovoltaic power P.sub.PV to POI **310**. For example, controller **314** may determine that it is desirable for PV field power inverter **304** to provide less than all of the photovoltaic power P.sub.PV to POI **310** to prevent the ramp rate from being exceeded and/or to prevent the power at POI **310** from exceeding a power limit.

(62) Battery power inverter **308** uses the battery power setpoint u.sub.bat to control an amount of power charged or discharged by battery **306**. The battery power setpoint u.sub.bat may be positive if controller **314** determines that battery power inverter **308** is to draw power from battery **306** or negative if controller **314** determines that battery power inverter **308** is to store power in battery **306**. The magnitude of u.sub.bat controls the rate at which energy is charged or discharged by battery **306**.

(63) Controller **314** may generate u.sub.PV and u.sub.bat based on a variety of different variables including, for example, a power signal from PV field **302** (e.g., current and previous values for P.sub.PV), the current state-of-charge (SOC) of battery **306**, a maximum battery power limit, a maximum power limit at POI **310**, the ramp rate limit, the grid frequency of energy grid **312**, and/or other variables that can be used by controller **314** to perform ramp rate control and/or frequency regulation. Advantageously, controller **314** generates values for u.sub.PV and u.sub.bat that maintain the ramp rate of the PV power within the ramp rate compliance limit while participating in the regulation of grid frequency and maintaining the SOC of battery **306** within a predetermined desirable range.

(64) An exemplary controller which can be used as controller **314** and exemplary processes which may be performed by controller **314** to generate the PV power setpoint u.sub.PV and the battery power setpoint u.sub.bat are described in detail in U.S. patent application Ser. No. 15/247,869 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,844 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,788 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,872 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,880 filed Aug. 25, 2016, and U.S. patent application Ser. No. 15/247,873 filed Aug. 25, 2016. The entire disclosure of each of these patent applications is incorporated by reference herein.

(65) Energy Storage System with Thermal and Electrical Energy Storage

(66) Referring now to FIG. **5**A, a block diagram of an energy storage system **500** is shown, according to an exemplary embodiment. Energy storage system **500** is shown to include a building **502**. Building **502** may be the same or similar to buildings **116**, as described with reference to FIG. **1**. For example, building **502** may be equipped with a HVAC system and/or a building management system that operates to control conditions within building **502**. In some embodiments, building **502** includes multiple buildings (i.e., a campus) served by energy storage system **500**. Building **502** may demand various resources including, for example, hot thermal energy (e.g., hot water), cold thermal energy (e.g., cold water), and/or electrical energy. The resources may be demanded by equipment or subsystems within building **502** or by external systems that provide services for building **502** (e.g., heating, cooling, air circulation, lighting, electricity, etc.). Energy storage system **500** operates to satisfy the resource demand associated with building **502**.

(67) Energy storage system **500** is shown to include a plurality of utilities **510**. Utilities **510** may provide energy storage system **500** with resources such as electricity, water, natural gas, or any other resource that can be used by energy storage system **500** to satisfy the demand of building **502**. For example, utilities **510** are shown to include an electric utility **511**, a water utility **512**, a natural gas utility **513**, and utility M **514**, where M is the total number of utilities **510**. In some embodiments, utilities **510** are commodity suppliers from which resources and other types of commodities can be purchased. Resources purchased from utilities **510** can be used by generator subplants **520** to produce generated resources (e.g., hot water, cold water, electricity, steam, etc.), stored in storage subplants **530** for later use, or provided directly to building **502**. For example, utilities **510** are shown providing electricity directly to building **502** and storage subplants **530**.

(68) Energy storage system **500** is shown to include a plurality of generator subplants **520**. In some embodiments, generator subplants **520** are components of a central plant (e.g., central plant **118**). Generator subplants **520** are shown to include a heater subplant **521**, a chiller subplant **522**, a heat recovery chiller subplant **523**, a steam subplant **524**, an electricity subplant **525**, and subplant N, where N is the total number of generator subplants **520**. Generator subplants **520** may be configured to convert one or more input resources into one or more output resources by operation of the equipment within generator subplants **520**. For example, heater subplant **521** may be configured to generate hot thermal energy (e.g., hot water) by heating water using electricity or natural gas. Chiller subplant **522** may be configured to generate cold thermal energy (e.g., cold water) by chilling water using electricity. Heat recovery chiller subplant **523** may be configured to generate hot thermal energy and cold thermal energy by removing heat from one water supply and adding the heat to another water supply. Steam subplant **524** may be configured to generate steam by boiling water using electricity or natural gas. Electricity subplant **525** may be configured to generate electricity using mechanical generators (e.g., a steam turbine, a gas-powered generator, etc.) or other types of electricity-generating equipment (e.g., photovoltaic equipment, hydroelectric equipment, etc.).

(69) The input resources used by generator subplants **520** may be provided by utilities **510**, retrieved from storage subplants **530**, and/or generated by other generator subplants **520**. For example, steam subplant **524** may produce steam as an output resource. Electricity subplant **525** may include a steam turbine that uses the steam generated by steam subplant **524** as an input resource to generate electricity. The output resources produced by generator subplants **520** may be stored in storage subplants **530**, provided to building **502**, sold to energy purchasers **504**, and/or used by other generator subplants **520**. For example, the electricity generated by electricity subplant **525** may be stored in electrical energy storage **533**, used by chiller subplant **522** to generate cold thermal energy, provided to building **502**, and/or sold to energy purchasers **504**.

(70) Energy storage system **500** is shown to include storage subplants **530**. In some embodiments, storage subplants **530** are components of a central plant (e.g., central plant **118**). Storage subplants **530** may be configured to store energy and other types of resources for later use. Each of storage subplants **530** may be configured to store a different type of resource. For example, storage subplants **530** are shown to include hot thermal energy storage **531** (e.g., one or more hot water storage tanks), cold thermal energy storage **532** (e.g., one or more cold thermal energy storage tanks), electrical energy storage **533** (e.g., one or more batteries), and resource type P storage **534**, where P is the total number of storage subplants **530**. The resources stored in subplants **530** may be purchased directly from utilities **510** or generated by generator subplants **520**.

(71) In some embodiments, storage subplants **530** are used by energy storage system **500** to take advantage of price-based demand response (PBDR) programs. PBDR programs encourage consumers to reduce consumption when generation, transmission, and distribution costs are high. PBDR programs are typically implemented (e.g., by utilities **510**) in the form of energy prices that vary as a function of time. For example, utilities **510** may increase the price per unit of electricity during peak usage hours to encourage customers to reduce electricity consumption during peak times. Some utilities also charge consumers a separate demand charge based on the maximum rate of electricity consumption at any time during a predetermined demand charge period.

(72) Advantageously, storing energy and other types of resources in subplants **530** allows for the resources to be purchased at times when the

resources are relatively less expensive (e.g., during non-peak electricity hours) and stored for use at times when the resources are relatively more expensive (e.g., during peak electricity hours). Storing resources in subplants **530** also allows the resource demand of building **502** to be shifted in time. For example, resources can be purchased from utilities **510** at times when the demand for heating or cooling is low and immediately converted into hot or cold thermal energy by generator subplants **520**. The thermal energy can be stored in storage subplants **530** and retrieved at times when the demand for heating or cooling is high. This allows energy storage system **500** to smooth the resource demand of building **502** and reduces the maximum required capacity of generator subplants **520**. Smoothing the demand also allows energy storage system **500** to reduce the peak electricity consumption, which results in a lower demand charge.

(73) In some embodiments, storage subplants **530** are used by energy storage system **500** to take advantage of incentive-based demand response (IBDR) programs. IBDR programs provide incentives to customers who have the capability to store energy, generate energy, or curtail energy usage upon request. Incentives are typically provided in the form of monetary revenue paid by utilities **510** or by an independent service operator (ISO). IBDR programs supplement traditional utility-owned generation, transmission, and distribution assets with additional options for modifying demand load curves. For example, stored energy can be sold to energy purchasers **504** (e.g., an energy grid) to supplement the energy generated by utilities **510**. In some instances, incentives for participating in an IBDR program vary based on how quickly a system can respond to a request to change power output/consumption. Faster responses may be compensated at a higher level. Advantageously, electrical energy storage **533** allows system **500** to quickly respond to a request for electric power by rapidly discharging stored electrical energy to energy purchasers **504**.

(74) Still referring to FIG. **5**A, energy storage system **500** is shown to include an energy storage controller **506**. Energy storage controller **506** may be configured to control the distribution, production, storage, and usage of resources in energy storage system **500**. In some embodiments, energy storage controller **506** performs an optimization process determine an optimal set of control decisions for each time step within an optimization period. The control decisions may include, for example, an optimal amount of each resource to purchase from utilities **510**, an optimal amount of each resource to produce or convert using generator subplants **520**, an optimal amount of each resource to store or remove from storage subplants **530**, an optimal amount of each resource to sell to energy purchasers **504**, and/or an optimal amount of each resource to provide to building **502**. In some embodiments, the control decisions include an optimal amount of each input resource and output resource for each of generator subplants **520**.

(75) Controller **506** may be configured to maximize the economic value of operating energy storage system **500** over the duration of the optimization period. The economic value may be defined by a value function that expresses economic value as a function of the control decisions made by controller **506**. The value function may account for the cost of resources purchased from utilities **510**, revenue generated by selling resources to energy purchasers **504**, and the cost of operating energy storage system **500**. In some embodiments, the cost of operating energy storage system **500** includes a cost for losses in battery capacity as a result of the charging and discharging electrical energy storage **533**. The cost of operating energy storage system **500** may also include a cost of excessive equipment start/stops during the optimization period.

(76) Each of subplants **520**-**530** may include equipment that can be controlled by energy storage controller **506** to optimize the performance of energy storage system **500**. Subplant equipment may include, for example, heating devices, chillers, heat recovery heat exchangers, cooling towers, energy storage devices, pumps, valves, and/or other devices of subplants **520**-**530**. Individual devices of generator subplants **520** can be turned on or off to adjust the resource production of each generator subplant. In some embodiments, individual devices of generator subplants **520** can be operated at variable capacities (e.g., operating a chiller at 10% capacity or 60% capacity) according to an operating setpoint received from energy storage controller **506**.

(77) In some embodiments, one or more of subplants **520**-**530** includes a subplant level controller configured to control the equipment of the corresponding subplant. For example, energy storage controller **506** may determine an on/off configuration and global operating setpoints for the subplant equipment. In response to the on/off configuration and received global operating setpoints, the subplant controllers may turn individual devices of their respective equipment on or off, and implement specific operating setpoints (e.g., damper position, vane position, fan speed, pump speed, etc.) to reach or maintain the global operating setpoints.

(78) In some embodiments, controller **506** maximizes the life cycle economic value of energy storage system **500** while participating in PBDR programs, IBDR programs, or simultaneously in both PBDR and IBDR programs. For the IBDR programs, controller **506** may use statistical estimates of past clearing prices, mileage ratios, and event probabilities to determine the revenue generation potential of selling stored energy to energy purchasers **504**. For the PBDR programs, controller **506** may use predictions of ambient conditions, facility thermal loads, and thermodynamic models of installed equipment to estimate the resource consumption of subplants **520**. Controller **506** may use predictions of the resource consumption to monetize the costs of running the equipment.

(79) Controller **506** may automatically determine (e.g., without human intervention) a combination of PBDR and/or IBDR programs in which to participate over the optimization period in order to maximize economic value. For example, controller **506** may consider the revenue generation potential of IBDR programs, the cost reduction potential of PBDR programs, and the equipment maintenance/replacement costs that would result from participating in various combinations of the IBDR programs and PBDR programs. Controller **506** may weigh the benefits of participation against the costs of participation to determine an optimal combination of programs in which to participate. Advantageously, this allows controller **506** to determine an optimal set of control decisions that maximize the overall value of operating energy storage system **500**.

(80) In some instances, controller **506** may determine that it would be beneficial to participate in an IBDR program when the revenue generation potential is high and/or the costs of participating are low. For example, controller **506** may receive notice of a synchronous reserve event from an IBDR program which requires energy storage system **500** to shed a predetermined amount of power. Controller **506** may determine that it is optimal to participate in the IBDR program if cold thermal energy storage **532** has enough capacity to provide cooling for building **502** while the load on chiller subplant **522** is reduced in order to shed the predetermined amount of power.

(81) In other instances, controller **506** may determine that it would not be beneficial to participate in an IBDR program when the resources required to participate are better allocated elsewhere. For example, if building **502** is close to setting a new peak demand that would greatly increase the PBDR costs, controller **506** may determine that only a small portion of the electrical energy stored in electrical energy storage **533** will be sold to energy purchasers **504** in order to participate in a frequency response market. Controller **506** may determine that the remainder of the electrical energy will be used to power chiller subplant **522** to prevent a new peak demand from being set.

(82) In some embodiments, energy storage system **500** and controller include some or all of the components and/or features described in U.S. patent application Ser. No. 15/247,875 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,879 filed Aug. 25, 2016, and U.S. patent application Ser. No. 15/247,881 filed Aug. 25, 2016. The entire disclosure of each of these patent applications is incorporated by reference herein.

(83) Energy Cost Optimization System

(84) Referring now to FIG. **5**B, a block diagram of an energy cost optimization system **550** is shown, according to an exemplary embodiment. Energy cost optimization system **550** is shown to include many of the same components as energy storage system **500** (described with reference to FIG. **5**A) with the exception of storage subplants **530**. System **550** is an example of a system without thermal or electrical energy storage in which the peak load contribution cost optimization techniques can be implemented.

(85) Energy cost optimization system **550** is shown to include a building **502**. Building **502** may be the same or similar to buildings **116**, as described with reference to FIG. **1**. For example, building **502** may be equipped with a HVAC system and/or a building management system that operates to control conditions within building **502**. In some embodiments, building **502** includes multiple buildings (i.e., a campus) served by energy cost optimization system **550**. Building **502** may demand various resources including, for example, hot thermal energy (e.g., hot water), cold thermal energy (e.g., cold water), and/or electrical energy. The resources may be demanded by equipment or subsystems within building **502** or by external systems that provide services for building **502** (e.g., heating, cooling, air circulation, lighting, electricity, etc.). Energy cost optimization system **550**

operates to satisfy the resource demand associated with building **502**.
(86) Energy cost optimization system **550** is shown to include a plurality of utilities **510**. Utilities **510** may provide system **550** with resources such as electricity, water, natural gas, or any other resource that can be used by system **550** to satisfy the demand of building **502**. For example, utilities **510** are shown to include an electric utility **511**, a water utility **512**, a natural gas utility **513**, and utility M **514**, where M is the total number of utilities **510**. In some embodiments, utilities **510** are commodity suppliers from which resources and other types of commodities can be purchased. Resources purchased from utilities **510** can be used by generator subplants **520** to produce generated resources (e.g., hot water, cold water, electricity, steam, etc.) or provided directly to building **502**. For example, utilities **510** are shown providing electricity directly to building **502**.
(87) Energy cost optimization system **550** is shown to include a plurality of generator subplants **520**. Generator subplants **520** are shown to include a heater subplant **521**, a chiller subplant **522**, a heat recovery chiller subplant **523**, a steam subplant **524**, an electricity subplant **525**, and subplant N, where N is the total number of generator subplants **520**. Generator subplants **520** may be configured to convert one or more input resources into one or more output resources by operation of the equipment within generator subplants **520**. For example, heater subplant **521** may be configured to generate hot thermal energy (e.g., hot water) by heating water using electricity or natural gas. Chiller subplant **522** may be configured to generate cold thermal energy (e.g., cold water) by chilling water using electricity. Heat recovery chiller subplant **523** may be configured to generate hot thermal energy and cold thermal energy by removing heat from one water supply and adding the heat to another water supply. Steam subplant **524** may be configured to generate steam by boiling water using electricity or natural gas. Electricity subplant **525** may be configured to generate electricity using mechanical generators (e.g., a steam turbine, a gas-powered generator, etc.) or other types of electricity-generating equipment (e.g., photovoltaic equipment, hydroelectric equipment, etc.).
(88) The input resources used by generator subplants **520** may be provided by utilities **510** and/or generated by other generator subplants **520**. For example, steam subplant **524** may produce steam as an output resource. Electricity subplant **525** may include a steam turbine that uses the steam generated by steam subplant **524** as an input resource to generate electricity. The output resources produced by generator subplants **520** may be provided to building **502**, sold to energy purchasers **504**, and/or used by other generator subplants **520**. For example, the electricity generated by electricity subplant **525** may be used by chiller subplant **522** to generate cold thermal energy, provided to building **502**, and/or sold to energy purchasers **504**.
(89) Still referring to FIG. **5**B, energy cost optimization system **550** is shown to include a controller **552**. Controller **552** may be configured to control the distribution, production, and usage of resources in system **550**. In some embodiments, controller **552** performs an optimization process determine an optimal set of control decisions for each time step within an optimization period. The control decisions may include, for example, an optimal amount of each resource to purchase from utilities **510**, an optimal amount of each resource to produce or convert using generator subplants **520**, an optimal amount of each resource to sell to energy purchasers **504**, and/or an optimal amount of each resource to provide to building **502**. In some embodiments, the control decisions include an optimal amount of each input resource and output resource for each of generator subplants **520**.
(90) Controller **552** may be configured to maximize the economic value of operating energy cost optimization system **550** over the duration of the optimization period. The economic value may be defined by a value function that expresses economic value as a function of the control decisions made by controller **552**. The value function may account for the cost of resources purchased from utilities **510**, revenue generated by selling resources to energy purchasers **504**, and the cost of operating system **550**. In some embodiments, the cost of operating system **550** includes a cost of excessive equipment start/stops during the optimization period.
(91) Each of subplants **520** may include equipment that can be controlled by controller **552** to optimize the performance of system **550**. Subplant equipment may include, for example, heating devices, chillers, heat recovery heat exchangers, cooling towers, pumps, valves, and/or other devices of subplants **520**. Individual devices of generator subplants **520** can be turned on or off to adjust the resource production of each generator subplant. In some embodiments, individual devices of generator subplants **520** can be operated at variable capacities (e.g., operating a chiller at 10% capacity or 60% capacity) according to an operating setpoint received from controller **552**.
(92) In some embodiments, one or more of subplants **520** includes a subplant level controller configured to control the equipment of the corresponding subplant. For example, controller **552** may determine an on/off configuration and global operating setpoints for the subplant equipment. In response to the on/off configuration and received global operating setpoints, the subplant controllers may turn individual devices of their respective equipment on or off, and implement specific operating setpoints (e.g., damper position, vane position, fan speed, pump speed, etc.) to reach or maintain the global operating setpoints.
(93) In some embodiments, energy cost optimization system **550** and controller **552** include some or all of the components and/or features described in U.S. patent application Ser. No. 15/247,875 filed Aug. 25, 2016, U.S. patent application Ser. No. 15/247,879 filed Aug. 25, 2016, and U.S. patent application Ser. No. 15/247,881 filed Aug. 25, 2016. The entire disclosure of each of these patent applications is incorporated by reference herein.
(94) Energy Storage Controller
(95) Referring now to FIG. **6**A, a block diagram illustrating energy storage controller **506** in greater detail is shown, according to an exemplary embodiment. Energy storage controller **506** is shown providing control decisions to a building management system (BMS) **606**. In some embodiments, BMS **606** is the same or similar the BMS described with reference to FIG. **1**. The control decisions provided to BMS **606** may include resource purchase amounts for utilities **510**, setpoints for generator subplants **520**, and/or charge/discharge rates for storage subplants **530**.
(96) BMS **606** may be configured to monitor conditions within a controlled building or building zone. For example, BMS **606** may receive input from various sensors (e.g., temperature sensors, humidity sensors, airflow sensors, voltage sensors, etc.) distributed throughout the building and may report building conditions to energy storage controller **506**. Building conditions may include, for example, a temperature of the building or a zone of the building, a power consumption (e.g., electric load) of the building, a state of one or more actuators configured to affect a controlled state within the building, or other types of information relating to the controlled building. BMS **606** may operate subplants **520-530** to affect the monitored conditions within the building and to serve the thermal energy loads of the building.
(97) BMS **606** may receive control signals from energy storage controller **506** specifying on/off states, charge/discharge rates, and/or setpoints for the subplant equipment. BMS **606** may control the equipment (e.g., via actuators, power relays, etc.) in accordance with the control signals provided by energy storage controller **506**. For example, BMS **606** may operate the equipment using closed loop control to achieve the setpoints specified by energy storage controller **506**. In various embodiments, BMS **606** may be combined with energy storage controller **506** or may be part of a separate building management system. According to an exemplary embodiment, BMS **606** is a METASYS® brand building management system, as sold by Johnson Controls, Inc.
(98) Energy storage controller **506** may monitor the status of the controlled building using information received from BMS **606**. Energy storage controller **506** may be configured to predict the thermal energy loads (e.g., heating loads, cooling loads, etc.) of the building for plurality of time steps in an optimization period (e.g., using weather forecasts from a weather service **604**). Energy storage controller **506** may also predict the revenue generation potential of IBDR programs using an incentive event history (e.g., past clearing prices, mileage ratios, event probabilities, etc.) from incentive programs **602**. Energy storage controller **506** may generate control decisions that optimize the economic value of operating energy storage system **500** over the duration of the optimization period subject to constraints on the optimization process (e.g., energy balance constraints, load satisfaction constraints, etc.). The optimization process performed by energy storage controller **506** is described in greater detail below.
(99) According to an exemplary embodiment, energy storage controller **506** is integrated within a single computer (e.g., one server, one housing, etc.). In various other exemplary embodiments, energy storage controller **506** can be distributed across multiple servers or computers (e.g., that can exist in distributed locations). In another exemplary embodiment, energy storage controller **506** may integrated with a smart building manager that manages multiple building systems and/or combined with BMS **606**.

(100) Energy storage controller **506** is shown to include a communications interface **636** and a processing circuit **607**. Communications interface **636** may include wired or wireless interfaces (e.g., jacks, antennas, transmitters, receivers, transceivers, wire terminals, etc.) for conducting data communications with various systems, devices, or networks. For example, communications interface **636** may include an Ethernet card and port for sending and receiving data via an Ethernet-based communications network and/or a WiFi transceiver for communicating via a wireless communications network. Communications interface **636** may be configured to communicate via local area networks or wide area networks (e.g., the Internet, a building WAN, etc.) and may use a variety of communications protocols (e.g., BACnet, IP, LON, etc.).
(101) Communications interface **636** may be a network interface configured to facilitate electronic data communications between energy storage controller **506** and various external systems or devices (e.g., BMS **606**, subplants **520-530**, utilities **510**, etc.). For example, energy storage controller **506** may receive information from BMS **606** indicating one or more measured states of the controlled building (e.g., temperature, humidity, electric loads, etc.) and one or more states of subplants **520-530** (e.g., equipment status, power consumption, equipment availability, etc.). Communications interface **636** may receive inputs from BMS **606** and/or subplants **520-530** and may provide operating parameters (e.g., on/off decisions, setpoints, etc.) to subplants **520-530** via BMS **606**. The operating parameters may cause subplants **520-530** to activate, deactivate, or adjust a setpoint for various devices thereof.
(102) Still referring to FIG. **6**A, processing circuit **607** is shown to include a processor **608** and memory **610**. Processor **608** may be a general purpose or specific purpose processor, an application specific integrated circuit (ASIC), one or more field programmable gate arrays (FPGAs), a group of processing components, or other suitable processing components. Processor **608** may be configured to execute computer code or instructions stored in memory **610** or received from other computer readable media (e.g., CDROM, network storage, a remote server, etc.).
(103) Memory **610** may include one or more devices (e.g., memory units, memory devices, storage devices, etc.) for storing data and/or computer code for completing and/or facilitating the various processes described in the present disclosure. Memory **610** may include random access memory (RAM), read-only memory (ROM), hard drive storage, temporary storage, non-volatile memory, flash memory, optical memory, or any other suitable memory for storing software objects and/or computer instructions. Memory **610** may include database components, object code components, script components, or any other type of information structure for supporting the various activities and information structures described in the present disclosure. Memory **610** may be communicably connected to processor **608** via processing circuit **607** and may include computer code for executing (e.g., by processor **608**) one or more processes described herein.
(104) Memory **610** is shown to include a building status monitor **624**. Energy storage controller **506** may receive data regarding the overall building or building space to be heated or cooled by system **500** via building status monitor **624**. In an exemplary embodiment, building status monitor **624** may include a graphical user interface component configured to provide graphical user interfaces to a user for selecting building requirements (e.g., overall temperature parameters, selecting schedules for the building, selecting different temperature levels for different building zones, etc.).
(105) Energy storage controller **506** may determine on/off configurations and operating setpoints to satisfy the building requirements received from building status monitor **624**. In some embodiments, building status monitor **624** receives, collects, stores, and/or transmits cooling load requirements, building temperature setpoints, occupancy data, weather data, energy data, schedule data, and other building parameters. In some embodiments, building status monitor **624** stores data regarding energy costs, such as pricing information available from utilities **510** (energy charge, demand charge, etc.).
(106) Still referring to FIG. **6**A, memory **610** is shown to include a load/rate predictor **622**. Load/rate predictor **622** may be configured to predict the thermal energy loads (custom character.sub.k) of the building or campus for each time step k (e.g., k=1 . . . n) of an optimization period. Load/rate predictor **622** is shown receiving weather forecasts from a weather service **604**. In some embodiments, load/rate predictor **622** predicts the thermal energy loads custom character.sub.k as a function of the weather forecasts. In some embodiments, load/rate predictor **622** uses feedback from BMS **606** to predict loads custom character.sub.k. Feedback from BMS **606** may include various types of sensory inputs (e.g., temperature, flow, humidity, enthalpy, etc.) or other data relating to the controlled building (e.g., inputs from a HVAC system, a lighting control system, a security system, a water system, etc.).
(107) In some embodiments, load/rate predictor **622** receives a measured electric load and/or previous measured load data from BMS **606** (e.g., via building status monitor **624**). Load/rate predictor **622** may predict loads custom character.sub.k as a function of a given weather forecast ({circumflex over (ϕ)}.sub.w), a day type (day), the time of day (t), and previous measured load data (Y.sub.k-1). Such a relationship is expressed in the following equation:
(108) $\hat{\ell}_k = f(\hat{\ }_w, \text{day}, t$ .Math. $Y_{k-1})$
(109) In some embodiments, load/rate predictor **622** uses a deterministic plus stochastic model trained from historical load data to predict loads custom character.sub.k. Load/rate predictor **622** may use any of a variety of prediction methods to predict loads custom character.sub.k (e.g., linear regression for the deterministic portion and an AR model for the stochastic portion). Load/rate predictor **622** may predict one or more different types of loads for the building or campus. For example, load/rate predictor **622** may predict a hot water load custom character.sub.Hot,k and a cold water load custom character.sub.cold,k for each time step k within the prediction window. In some embodiments, load/rate predictor **622** makes load/rate predictions using the techniques described in U.S. patent application Ser. No. 14/717,593.
(110) Load/rate predictor **622** is shown receiving utility rates from utilities **510**. Utility rates may indicate a cost or price per unit of a resource (e.g., electricity, natural gas, water, etc.) provided by utilities **510** at each time step k in the prediction window. In some embodiments, the utility rates are time-variable rates. For example, the price of electricity may be higher at certain times of day or days of the week (e.g., during high demand periods) and lower at other times of day or days of the week (e.g., during low demand periods). The utility rates may define various time periods and a cost per unit of a resource during each time period. Utility rates may be actual rates received from utilities **510** or predicted utility rates estimated by load/rate predictor **622**.
(111) In some embodiments, the utility rates include demand charges for one or more resources provided by utilities **510**. A demand charge may define a separate cost imposed by utilities **510** based on the maximum usage of a particular resource (e.g., maximum energy consumption) during a demand charge period. The utility rates may define various demand charge periods and one or more demand charges associated with each demand charge period. In some instances, demand charge periods may overlap partially or completely with each other and/or with the prediction window. Advantageously, demand response optimizer **630** may be configured to account for demand charges in the high level optimization process performed by high level optimizer **632**. Utilities **510** may be defined by time-variable (e.g., hourly) prices, a maximum service level (e.g., a maximum rate of consumption allowed by the physical infrastructure or by contract) and, in the case of electricity, a demand charge or a charge for the peak rate of consumption within a certain period. Load/rate predictor **622** may store the predicted loads custom character.sub.k and the utility rates in memory **610** and/or provide the predicted loads custom character.sub.k and the utility rates to demand response optimizer **630**.
(112) Still referring to FIG. **6**A, memory **610** is shown to include an incentive estimator **620**. Incentive estimator **620** may be configured to estimate the revenue generation potential of participating in various incentive-based demand response (IBDR) programs. In some embodiments, incentive estimator **620** receives an incentive event history from incentive programs **602**. The incentive event history may include a history of past IBDR events from incentive programs **602**. An IBDR event may include an invitation from incentive programs **602** to participate in an IBDR program in exchange for a monetary incentive. The incentive event history may indicate the times at which the past IBDR events occurred and attributes describing the IBDR events (e.g., clearing prices, mileage ratios, participation requirements, etc.). Incentive estimator **620** may use the incentive event history to estimate IBDR event probabilities during the optimization period.
(113) Incentive estimator **620** is shown providing incentive predictions to demand response optimizer **630**. The incentive predictions may include the estimated IBDR probabilities, estimated participation requirements, an estimated amount of revenue from participating in the estimated IBDR events,

and/or any other attributes of the predicted IBDR events. Demand response optimizer **630** may use the incentive predictions along with the predicted loads custom character.sub.k and utility rates from load/rate predictor **622** to determine an optimal set of control decisions for each time step within the optimization period.

(114) Still referring to FIG. **6**A, memory **610** is shown to include a demand response optimizer **630**. Demand response optimizer **630** may perform a cascaded optimization process to optimize the performance of energy storage system **500**. For example, demand response optimizer **630** is shown to include a high level optimizer **632** and a low level optimizer **634**. High level optimizer **632** may control an outer (e.g., subplant level) loop of the cascaded optimization. High level optimizer **632** may determine an optimal set of control decisions for each time step in the prediction window in order to optimize (e.g., maximize) the value of operating energy storage system **500**. Control decisions made by high level optimizer **632** may include, for example, load setpoints for each of generator subplants **520**, charge/discharge rates for each of storage subplants **530**, resource purchase amounts for each type of resource purchased from utilities **510**, and/or an amount of each resource sold to energy purchasers **504**. In other words, the control decisions may define resource allocation at each time step. The control decisions made by high level optimizer **632** are based on the statistical estimates of incentive event probabilities and revenue generation potential for various IBDR events as well as the load and rate predictions.

(115) Low level optimizer **634** may control an inner (e.g., equipment level) loop of the cascaded optimization. Low level optimizer **634** may determine how to best run each subplant at the load setpoint determined by high level optimizer **632**. For example, low level optimizer **634** may determine on/off states and/or operating setpoints for various devices of the subplant equipment in order to optimize (e.g., minimize) the energy consumption of each subplant while meeting the resource allocation setpoint for the subplant. In some embodiments, low level optimizer **634** receives actual incentive events from incentive programs **602**. Low level optimizer **634** may determine whether to participate in the incentive events based on the resource allocation set by high level optimizer **632**. For example, if insufficient resources have been allocated to a particular IBDR program by high level optimizer **632** or if the allocated resources have already been used, low level optimizer **634** may determine that energy storage system **500** will not participate in the IBDR program and may ignore the IBDR event. However, if the required resources have been allocated to the IBDR program and are available in storage subplants **530**, low level optimizer **634** may determine that system **500** will participate in the IBDR program in response to the IBDR event. The cascaded optimization process performed by demand response optimizer **630** is described in greater detail in U.S. patent application Ser. No. 15/247,885.

(116) Still referring to FIG. **6**A, memory **610** is shown to include a subplant control module **628**. Subplant control module **628** may store historical data regarding past operating statuses, past operating setpoints, and instructions for calculating and/or implementing control parameters for subplants **520-530**. Subplant control module **628** may also receive, store, and/or transmit data regarding the conditions of individual devices of the subplant equipment, such as operating efficiency, equipment degradation, a date since last service, a lifespan parameter, a condition grade, or other device-specific data. Subplant control module **628** may receive data from subplants **520-530** and/or BMS **606** via communications interface **636**. Subplant control module **628** may also receive and store on/off statuses and operating setpoints from low level optimizer **634**.

(117) Data and processing results from demand response optimizer **630**, subplant control module **628**, or other modules of energy storage controller **506** may be accessed by (or pushed to) monitoring and reporting applications **626**. Monitoring and reporting applications **626** may be configured to generate real time "system health" dashboards that can be viewed and navigated by a user (e.g., a system engineer). For example, monitoring and reporting applications **626** may include a web-based monitoring application with several graphical user interface (GUI) elements (e.g., widgets, dashboard controls, windows, etc.) for displaying key performance indicators (KPI) or other information to users of a GUI. In addition, the GUI elements may summarize relative energy use and intensity across energy storage systems in different buildings (real or modeled), different campuses, or the like. Other GUI elements or reports may be generated and shown based on available data that allow users to assess performance across one or more energy storage systems from one screen. The user interface or report (or underlying data engine) may be configured to aggregate and categorize operating conditions by building, building type, equipment type, and the like. The GUI elements may include charts or histograms that allow the user to visually analyze the operating parameters and power consumption for the devices of the energy storage system.

(118) Still referring to FIG. **6**A, energy storage controller **506** may include one or more GUI servers, web services **612**, or GUI engines **614** to support monitoring and reporting applications **626**. In various embodiments, applications **626**, web services **612**, and GUI engine **614** may be provided as separate components outside of energy storage controller **506** (e.g., as part of a smart building manager). Energy storage controller **506** may be configured to maintain detailed historical databases (e.g., relational databases, XML databases, etc.) of relevant data and includes computer code modules that continuously, frequently, or infrequently query, aggregate, transform, search, or otherwise process the data maintained in the detailed databases. Energy storage controller **506** may be configured to provide the results of any such processing to other databases, tables, XML files, or other data structures for further querying, calculation, or access by, for example, external monitoring and reporting applications.

(119) Energy storage controller **506** is shown to include configuration tools **616**. Configuration tools **616** can allow a user to define (e.g., via graphical user interfaces, via prompt-driven "wizards," etc.) how energy storage controller **506** should react to changing conditions in the energy storage subsystems. In an exemplary embodiment, configuration tools **616** allow a user to build and store condition-response scenarios that can cross multiple energy storage system devices, multiple building systems, and multiple enterprise control applications (e.g., work order management system applications, entity resource planning applications, etc.). For example, configuration tools **616** can provide the user with the ability to combine data (e.g., from subsystems, from event histories) using a variety of conditional logic. In varying exemplary embodiments, the conditional logic can range from simple logical operators between conditions (e.g., AND, OR, XOR, etc.) to pseudo-code constructs or complex programming language functions (allowing for more complex interactions, conditional statements, loops, etc.). Configuration tools **616** can present user interfaces for building such conditional logic. The user interfaces may allow users to define policies and responses graphically. In some embodiments, the user interfaces may allow a user to select a pre-stored or pre-constructed policy and adapt it or enable it for use with their system.

(120) Energy Cost Optimization Controller

(121) Referring now to FIG. **6**B, a block diagram illustrating controller **552** in greater detail is shown, according to an exemplary embodiment. Controller **552** is shown providing control decisions to a building management system (BMS) **606**. In some embodiments, BMS **606** is the same or similar the BMS described with reference to FIG. **1**. The control decisions provided to BMS **606** may include resource purchase amounts for utilities **510** and/or setpoints for generator subplants **520**.

(122) BMS **606** may be configured to monitor conditions within a controlled building or building zone. For example, BMS **606** may receive input from various sensors (e.g., temperature sensors, humidity sensors, airflow sensors, voltage sensors, etc.) distributed throughout the building and may report building conditions to controller **552**. Building conditions may include, for example, a temperature of the building or a zone of the building, a power consumption (e.g., electric load) of the building, a state of one or more actuators configured to affect a controlled state within the building, or other types of information relating to the controlled building. BMS **606** may operate subplants **520** to affect the monitored conditions within the building and to serve the thermal energy loads of the building.

(123) BMS **606** may receive control signals from controller **552** specifying on/off states and/or setpoints for the subplant equipment. BMS **606** may control the equipment (e.g., via actuators, power relays, etc.) in accordance with the control signals provided by controller **552**. For example, BMS **606** may operate the equipment using closed loop control to achieve the setpoints specified by energy storage controller **552**. In various embodiments, BMS **606** may be combined with controller **552** or may be part of a separate building management system. According to an exemplary embodiment, BMS **606** is a METASYS® brand building management system, as sold by Johnson Controls, Inc.

(124) Controller **552** may monitor the status of the controlled building using information received from BMS **606**. Controller **552** may be configured to predict the thermal energy loads (e.g., heating loads, cooling loads, etc.) of the building for plurality of time steps in an optimization period (e.g., using weather forecasts from a weather service **604**). Controller **552** may generate control decisions that optimize the economic value of operating

system **550** over the duration of the optimization period subject to constraints on the optimization process (e.g., energy balance constraints, load satisfaction constraints, etc.). The optimization process performed by controller **552** is described in greater detail below.
(125) Controller **552** is shown to include a communications interface **636** and a processing circuit **607** having a processor **608** and memory **610**. These components may be the same as described with reference to FIG. **6**A. For example, controller **552** is shown to include demand response optimizer **630**. Demand response optimizer **630** may perform a cascaded optimization process to optimize the performance of system **550**. For example, demand response optimizer **630** is shown to include a high level optimizer **632** and a low level optimizer **634**. High level optimizer **632** may control an outer (e.g., subplant level) loop of the cascaded optimization. High level optimizer **632** may determine an optimal set of control decisions for each time step in the prediction window in order to optimize (e.g., maximize) the value of operating energy storage system **500**. Control decisions made by high level optimizer **632** may include, for example, load setpoints for each of generator subplants **520**, resource purchase amounts for each type of resource purchased from utilities **510**, and/or an amount of each resource sold to energy purchasers **504**. In other words, the control decisions may define resource allocation at each time step.
(126) Low level optimizer **634** may control an inner (e.g., equipment level) loop of the cascaded optimization. Low level optimizer **634** may determine how to best run each subplant at the load setpoint determined by high level optimizer **632**. For example, low level optimizer **634** may determine on/off states and/or operating setpoints for various devices of the subplant equipment in order to optimize (e.g., minimize) the energy consumption of each subplant while meeting the resource allocation setpoint for the subplant. The cascaded optimization process performed by demand response optimizer **630** is described in greater detail in U.S. patent application Ser. No. 15/247,885. These and other components of controller **552** may be the same as previously described with reference to FIG. **6**A.
(127) Planning Tool
(128) Referring now to FIG. **7**, a block diagram of a planning system **700** is shown, according to an exemplary embodiment. Planning system **700** may be configured to use demand response optimizer **630** as part of a planning tool **702** to simulate the operation of a central plant over a predetermined time period (e.g., a day, a month, a week, a year, etc.) for planning, budgeting, and/or design considerations. When implemented in planning tool **702**, demand response optimizer **630** may operate in a similar manner as described with reference to FIGS. **6**A-**6**B. For example, demand response optimizer **630** may use building loads and utility rates to determine an optimal resource allocation to minimize cost over a simulation period. However, planning tool **702** may not be responsible for real-time control of a building management system or central plant.
(129) Planning tool **702** can be configured to determine the benefits of investing in a battery asset and the financial metrics associated with the investment. Such financial metrics can include, for example, the internal rate of return (IRR), net present value (NPV), and/or simple payback period (SPP). Planning tool **702** can also assist a user in determining the size of the battery which yields optimal financial metrics such as maximum NPV or a minimum SPP. In some embodiments, planning tool **702** allows a user to specify a battery size and automatically determines the benefits of the battery asset from participating in selected IBDR programs while performing PBDR, as described with reference to FIG. **5**A. In some embodiments, planning tool **702** is configured to determine the battery size that minimizes SPP given the IBDR programs selected and the requirement of performing PBDR. In some embodiments, planning tool **702** is configured to determine the battery size that maximizes NPV given the IBDR programs selected and the requirement of performing PBDR.
(130) In planning tool **702**, high level optimizer **632** may receive planned loads and utility rates for the entire simulation period. The planned loads and utility rates may be defined by input received from a user via a client device **722** (e.g., user-defined, user selected, etc.) and/or retrieved from a plan information database **726**. High level optimizer **632** uses the planned loads and utility rates in conjunction with subplant curves from low level optimizer **634** to determine an optimal resource allocation (i.e., an optimal dispatch schedule) for a portion of the simulation period.
(131) The portion of the simulation period over which high level optimizer **632** optimizes the resource allocation may be defined by a prediction window ending at a time horizon. With each iteration of the optimization, the prediction window is shifted forward and the portion of the dispatch schedule no longer in the prediction window is accepted (e.g., stored or output as results of the simulation). Load and rate predictions may be predefined for the entire simulation and may not be subject to adjustments in each iteration. However, shifting the prediction window forward in time may introduce additional plan information (e.g., planned loads and/or utility rates) for the newly-added time slice at the end of the prediction window. The new plan information may not have a significant effect on the optimal dispatch schedule since only a small portion of the prediction window changes with each iteration.
(132) In some embodiments, high level optimizer **632** requests all of the subplant curves used in the simulation from low level optimizer **634** at the beginning of the simulation. Since the planned loads and environmental conditions are known for the entire simulation period, high level optimizer **632** may retrieve all of the relevant subplant curves at the beginning of the simulation. In some embodiments, low level optimizer **634** generates functions that map subplant production to equipment level production and resource use when the subplant curves are provided to high level optimizer **632**. These subplant to equipment functions may be used to calculate the individual equipment production and resource use (e.g., in a post-processing module) based on the results of the simulation.
(133) Still referring to FIG. **7**, planning tool **702** is shown to include a communications interface **704** and a processing circuit **706**. Communications interface **704** may include wired or wireless interfaces (e.g., jacks, antennas, transmitters, receivers, transceivers, wire terminals, etc.) for conducting data communications with various systems, devices, or networks. For example, communications interface **704** may include an Ethernet card and port for sending and receiving data via an Ethernet-based communications network and/or a WiFi transceiver for communicating via a wireless communications network. Communications interface **704** may be configured to communicate via local area networks or wide area networks (e.g., the Internet, a building WAN, etc.) and may use a variety of communications protocols (e.g., BACnet, IP, LON, etc.).
(134) Communications interface **704** may be a network interface configured to facilitate electronic data communications between planning tool **702** and various external systems or devices (e.g., client device **722**, results database **728**, plan information database **726**, etc.). For example, planning tool **702** may receive planned loads and utility rates from client device **722** and/or plan information database **726** via communications interface **704**. Planning tool **702** may use communications interface **704** to output results of the simulation to client device **722** and/or to store the results in results database **728**.
(135) Still referring to FIG. **7**, processing circuit **706** is shown to include a processor **710** and memory **712**. Processor **710** may be a general purpose or specific purpose processor, an application specific integrated circuit (ASIC), one or more field programmable gate arrays (FPGAs), a group of processing components, or other suitable processing components. Processor **710** may be configured to execute computer code or instructions stored in memory **712** or received from other computer readable media (e.g., CDROM, network storage, a remote server, etc.).
(136) Memory **712** may include one or more devices (e.g., memory units, memory devices, storage devices, etc.) for storing data and/or computer code for completing and/or facilitating the various processes described in the present disclosure. Memory **712** may include random access memory (RAM), read-only memory (ROM), hard drive storage, temporary storage, non-volatile memory, flash memory, optical memory, or any other suitable memory for storing software objects and/or computer instructions. Memory **712** may include database components, object code components, script components, or any other type of information structure for supporting the various activities and information structures described in the present disclosure. Memory **712** may be communicably connected to processor **710** via processing circuit **706** and may include computer code for executing (e.g., by processor **710**) one or more processes described herein.
(137) Still referring to FIG. **7**, memory **712** is shown to include a GUI engine **716**, web services **714**, and configuration tools **718**. In an exemplary embodiment, GUI engine **716** includes a graphical user interface component configured to provide graphical user interfaces to a user for selecting or defining plan information for the simulation (e.g., planned loads, utility rates, environmental conditions, etc.). Web services **714** may allow a user to interact with planning tool **702** via a web portal and/or from a remote system or device (e.g., an enterprise control application).

(138) Configuration tools **718** can allow a user to define (e.g., via graphical user interfaces, via prompt-driven "wizards," etc.) various parameters of the simulation such as the number and type of subplants, the devices within each subplant, the subplant curves, device-specific efficiency curves, the duration of the simulation, the duration of the prediction window, the duration of each time step, and/or various other types of plan information related to the simulation. Configuration tools **718** can present user interfaces for building the simulation. The user interfaces may allow users to define simulation parameters graphically. In some embodiments, the user interfaces allow a user to select a pre-stored or pre-constructed simulated plant and/or plan information (e.g., from plan information database **726**) and adapt it or enable it for use in the simulation.
(139) Still referring to FIG. **7**, memory **712** is shown to include demand response optimizer **630**. Demand response optimizer **630** may use the planned loads and utility rates to determine an optimal resource allocation over a prediction window. The operation of demand response optimizer **630** may be the same or similar as previously described with reference to FIGS. **6-8**. With each iteration of the optimization process, demand response optimizer **630** may shift the prediction window forward and apply the optimal resource allocation for the portion of the simulation period no longer in the prediction window. Demand response optimizer **630** may use the new plan information at the end of the prediction window to perform the next iteration of the optimization process. Demand response optimizer **630** may output the applied resource allocation to reporting applications **730** for presentation to a client device **722** (e.g., via user interface **724**) or storage in results database **728**.
(140) Still referring to FIG. **7**, memory **712** is shown to include reporting applications **730**. Reporting applications **730** may receive the optimized resource allocations from demand response optimizer **630** and, in some embodiments, costs associated with the optimized resource allocations. Reporting applications **730** may include a web-based reporting application with several graphical user interface (GUI) elements (e.g., widgets, dashboard controls, windows, etc.) for displaying key performance indicators (KPI) or other information to users of a GUI. In addition, the GUI elements may summarize relative energy use and intensity across various plants, subplants, or the like. Other GUI elements or reports may be generated and shown based on available data that allow users to assess the results of the simulation. The user interface or report (or underlying data engine) may be configured to aggregate and categorize resource allocation and the costs associated therewith and provide the results to a user via a GUI. The GUI elements may include charts or histograms that allow the user to visually analyze the results of the simulation. An exemplary output that may be generated by reporting applications **730** is shown in FIG. **8**.
(141) Referring now to FIG. **8**, several graphs **800** illustrating the operation of planning tool **702** are shown, according to an exemplary embodiment. With each iteration of the optimization process, planning tool **702** selects an optimization period (i.e., a portion of the simulation period) over which the optimization is performed. For example, planning tool **702** may select optimization period **802** for use in the first iteration. Once the optimal resource allocation **810** has been determined, planning tool **702** may select a portion **818** of resource allocation **810** to send to plant dispatch **830**. Portion **818** may be the first b time steps of resource allocation **810**. Planning tool **702** may shift the optimization period **802** forward in time, resulting in optimization period **804**. The amount by which the prediction window is shifted may correspond to the duration of time steps b.
(142) Planning tool **702** may repeat the optimization process for optimization period **804** to determine the optimal resource allocation **812**. Planning tool **702** may select a portion **820** of resource allocation **812** to send to plant dispatch **830**. Portion **820** may be the first b time steps of resource allocation **812**. Planning tool **702** may then shift the prediction window forward in time, resulting in optimization period **806**. This process may be repeated for each subsequent optimization period (e.g., optimization periods **806**, **808**, etc.) to generate updated resource allocations (e.g., resource allocations **814**, **816**, etc.) and to select portions of each resource allocation (e.g., portions **822**, **824**) to send to plant dispatch **830**. Plant dispatch **830** includes the first b time steps **818-824** from each of optimization periods **802-808**. Once the optimal resource allocation is compiled for the entire simulation period, the results may be sent to reporting applications **730**, results database **728**, and/or client device **722**, as described with reference to FIG. **7**.
(143) Resource Allocation Optimization
(144) Referring now to FIG. **9**, a block diagram illustrating high level optimizer **632** in greater detail is shown, according to an exemplary embodiment. In some embodiments, high level optimizer **632** may be implemented as a component of energy storage controller **506**, as described with reference to FIGS. **5**A and **6**A. In other embodiments, high level optimizer **632** may be implemented as a component of controller **552**, as described with reference to FIGS. **5**B and **6**B. In other embodiments, high level optimizer **632** may be implemented as a component of planning tool **702**, as described with reference to FIGS. **7-8**.
(145) High level optimizer **632** may receive load and rate predictions from load/rate predictor **622**, incentive predictions from incentive estimator **620**, and subplant curves from low level optimizer **634**. High level optimizer **632** may determine an optimal resource allocation across energy storage system **500** as a function of the load and rate predictions, the incentive predictions, and the subplant curves. The optimal resource allocation may include an amount of each resource purchased from utilities **510**, an amount of each input and output resource of generator subplants **520**, an amount of each resource stored or withdrawn from storage subplants **530**, and/or an amount of each resource sold to energy purchasers **504**. In some embodiments, the optimal resource allocation maximizes the economic value of operating energy storage system **500** while satisfying the predicted loads for the building or campus.
(146) High level optimizer **632** can be configured to optimize the utilization of a battery asset, such as battery **108**, battery **306**, and/or electrical energy storage subplant **533**. A battery asset can be used to participate in IBDR programs which yield revenue and to reduce the cost of energy and the cost incurred from peak load contribution charges. High level optimizer **632** can use an optimization algorithm to optimally allocate a battery asset (e.g., by optimally charging and discharging the battery) to maximize its total value. In a planning tool framework, high level optimizer **632** can perform the optimization iteratively to determine optimal battery asset allocation for an entire simulation period (e.g., an entire year), as described with reference to FIG. **8**. The optimization process can be expanded to include economic load demand response (ELDR) and can account for peak load contribution charges. High level optimizer **632** can allocate the battery asset at each time step (e.g., each hour) over a given horizon such that energy and demand costs are minimized and frequency regulation (FR) revenue maximized. These and other features of high level optimizer **632** are described in detail below.
(147) In some embodiments, the high level optimizer **632** executes a stochastic model predictive control optimization process, for example as described in U.S. patent application Ser. No. 16/115,290, filed Aug. 28, 2018, the entire disclosure of which is incorporated by reference herein. For example, the high level optimizer **632** may obtain representative loads and rates for a plurality of scenarios, determine a peak demand target or other constraint by minimizing a risk attribute over the plurality of scenarios, and then use the peak demand target or other constraint as a constraint on an optimization of a cost function (e.g., the cost function J(x) defined below). Various implementations and adaptations of the systems and methods described in U.S. patent application Ser. No. 16/115,290 are contemplated by the present disclosure.
(148) Cost Function
(149) Still referring to FIG. **9**, high level optimizer **632** is shown to include a cost function module **902**. Cost function module **902** can generate a cost function or objective function which represents the total operating cost of a system over a time horizon (e.g., one month, one year, one day, etc.). The system can include any of the systems previously described (e.g., frequency response optimization system **100**, photovoltaic energy system **300**, energy storage system **500**, planning system **700**, etc.) or any other system in which high level optimizer **632** is implemented. In some embodiments, the cost function can be expressed generically using the following equation:
(150) $\underset{x}{\operatorname{argmin}} J(x)$
where J(x) is defined as follows:
(151) $J(x) = \sum_{sources} \sum_{horizon} \text{cost}(\text{purchase}_{resource,\,time}, \text{time}) - \sum_{incentives} \sum_{horizon} \text{revenue}(\text{ReservationAmount})$
(152) The first term in the previous equation represents the total cost of all resources purchased over the optimization horizon. Resources can

include, for example, water, electricity, natural gas, or other types of resources purchased from a utility or other outside entity. The second term in the equation represents the total revenue generated by participating in incentive programs (e.g., IBDR programs) over the optimization horizon. The revenue may be based on the amount of power reserved for participating in the incentive programs. Accordingly, the total cost function represents the total cost of resources purchased minus any revenue generated from participating in incentive programs. In some embodiments, the cost function also includes an equipment degradation term (e.g., a function of x) that accounts for a cost associated with equipment degradation resulting from use of the equipment over the horizon. In some embodiments, the cost function also includes an equipment maintenance term (e.g., a function of x) that accounts for a cost associated with maintaining the equipment over the horizon.

(153) High level optimizer **632** can optimize the cost function J(x) subject to the following constraint, which guarantees the balance between resources purchased, produced, discharged, consumed, and requested over the optimization horizon:

(154)

$$\underset{sources}{.\text{Math.}}\ \text{purchase}_{\text{resource, time}} + \underset{subplants}{.\text{Math.}}\ \text{produces}(x_{\text{internal, time}}, x_{\text{external, time}}, v_{\text{uncontrolled, time}}) - \underset{\text{subplants}}{.\text{Math.}}\ \text{consumes}(x_{\text{internal, time}}, x_{\text{external, time}}, v_{\text{uncontrolled, time}}) + \underset{\text{storage}}{.\text{Math}}$$

where x.sub.internal,time and x.sub.external,time are internal and external decision variables and v.sub.uncontrolled,time includes uncontrolled variables.

(155) The first term in the previous equation represents the total amount of each resource (e.g., electricity, water, natural gas, etc.) purchased from each source (e.g., utilities **510**) over the optimization horizon. The second term represents the total consumption of each resource within the system (e.g., by generator subplants **520**) over the optimization horizon. The third term represents the total amount of each resource discharged from storage (e.g., storage subplants **530**) over the optimization horizon. Positive values indicate that the resource is discharged from storage, whereas negative values indicate that the resource is charged or stored. The fourth term represents the total amount of each resource requested by various resource sinks (e.g., building **502**, energy purchasers **504**, or other resource consumers) over the optimization horizon. Accordingly, this constraint ensures that the total amount of each resource purchased, produced, or discharged from storage is equal to the amount of each resource consumed, stored, or provided to the resource sinks.

(156) In some embodiments, cost function module **902** separates the purchase cost of one or more resources into multiple terms. For example, cost function module **902** can separate the purchase cost of a resource into a first term corresponding to the cost per unit of the resource purchased (e.g., $/kWh of electricity, $/liter of water, etc.) and a second term corresponding to one or more demand charges. A demand charge is a separate charge on the consumption of a resource which depends on the maximum or peak resource consumption over a given period (i.e., a demand charge period). Cost function module **902** can express the cost function using the following equation:

(157)

$$J(x) = \underset{s \in \text{sources}}{.\text{Math.}} \left[\underset{q \in \text{demands}_s}{.\text{Math.}}\ w_{\text{demand}, s, q}\, r_{\text{demand}, s, q} \max_{i \in demand_{s,q}} (\text{purchase}_{s,i}) + \underset{horizon}{.\text{Math.}}\ r_{s,i}\, \text{purchase}_{s,i} \right] - \underset{incentives}{.\text{Math.}}\ \underset{horizon}{.\text{Math.}}\ \text{revenue(ReservationAmount)}$$

where r.sub.demand,s,q is the qth demand charge associated with the peak demand of the resource provided by source s over the demand charge period, w.sub.demand,s,q is the weight adjustment of the qth demand charge associated with source s, and the max( ) term indicates the maximum amount of the resource purchased from source s at any time step i during the demand charge period. The variable r.sub.s,i indicates the cost per unit of the resource purchased from source s and the variable purchases.sub.s,i indicates the amount of the resource purchased from source s during the ith time step of the optimization period.

(158) In some embodiments, the energy system in which high level optimizer **632** is implemented includes a battery asset (e.g., one or more batteries) configured to store and discharge electricity. If the battery asset is the only type of energy storage, cost function module **902** can simplify the cost function J(x) to the following equation:

(159) $$J(x) = -\underset{i=k}{\overset{k+h-1}{.\text{Math.}}}\ r_{e_i} P_{\text{bat}_i} \underset{i=k}{\overset{k+h-1}{.\text{Math.}}}\ r_{FR_i} P_{FR_i} + \underset{i=k}{\overset{k+h-1}{.\text{Math.}}}\ r_{s_i}\ .\text{Math.}\ P_{\text{bat}_i} - P_{\text{bat}_{i-1}}\ .\text{Math.} + w_d r_d \max_i(-P_{\text{bat}_i} + e\text{Load}_i)$$

where h is the duration of the optimization horizon, P.sub.bat.sub.i, is the amount of power (e.g., kW) discharged from the battery asset during the ith time step of the optimization horizon for use in reducing the amount of power purchased from an electric utility, r.sub.e.sub.i is the price of electricity (e.g., $/kWh) at time step i, P.sub.FR,i is the battery power (e.g., kW) committed to frequency regulation participation during time step i, r.sub.FR.sub.i is the incentive rate (e.g., $/kWh) for participating in frequency regulation during time step i, r.sub.d is the applicable demand charge (e.g., $/kWh) associated with the maximum electricity consumption during the corresponding demand charge period, w.sub.d is a weight adjustment of the demand charge over the horizon, and the max( ) term selects the maximum amount electricity purchased from the electric utility (e.g., kW) during any time step i of the applicable demand charge period.

(160) In the previous expression of the cost function J(x), the first term represents the cost savings resulting from the use of battery power to satisfy the electric demand of the facility relative to the cost which would have been incurred if the electricity were purchased from the electric utility. The second term represents the amount of revenue derived from participating in the frequency regulation program. The third term represents a switching penalty imposed for switching the battery power P.sub.bat between consecutive time steps. The fourth term represents the demand charge associated with the maximum amount of electricity purchased from the electric utility. The amount of electricity purchased may be equal to the difference between the electric load of the facility eLoad.sub.i (i.e., the total amount of electricity required) at time step i and the amount of power discharged from the battery asset P.sub.bat.sub.i at time step i. In a planning tool framework, historical data of the electric load eLoad over the horizon can be provided as a known input. In an operational mode, the electric load eLoad can be predicted for each time step of the optimization period.

(161) Optimization Constraints

(162) Still referring to FIG. **9**, high level optimizer **632** is shown to include a power constraints module **904**. Power constraints module **904** may be configured to impose one or more power constraints on the objective function J(x). In some embodiments, power constraints module **904** generates and imposes the following constraints:

P.sub.bat.sub.i+*P*.sub.FR.sub.i≤*P*.sub.eff

−*P*.sub.bat.sub.i+*P*.sub.FR.sub.i≤*P*.sub.eff

P.sub.bat.sub.i+*P*.sub.FR.sub.i≤eLoad.sub.i

where P.sub.bat.sub.i is the amount of power discharged from the battery at time step i for use in satisfying electric demand and reducing the demand charge, P.sub.FR.sub.i is the amount of battery power committed to frequency regulation at time step i, P.sub.eff is the effective power available (e.g., the maximum rate at which the battery can be charged or discharged), and eLoad.sub.i is the total electric demand at time step i.

(163) The first two power constraints ensure that the battery is not charged or discharged at a rate that exceeds the maximum battery charge/discharge rate P.sub.eff. If the system includes photovoltaic (PV) power generation, the effective power available P.sub.eff can be calculated as follows:

P.sub.eff=*P*.sub.rated−*P*.sub.PV FirmingReserve

where P.sub.rated is the rated capacity of the battery and P.sub.PV FirmingReserve is the PV firming reserve power. The third power constraint ensures that energy stored in the battery is not sold or exported to the energy grid. In some embodiments, power constraints module **904** can remove the third power constraint if selling energy back to the energy grid is a desired feature or behavior of the system.

(164) Still referring to FIG. **9**, high level optimizer **632** is shown to include a capacity constraints module **906**. Capacity constraints module **906** may be configured to impose one or more capacity constraints on the objective function J(x). The capacity constraints may be used to relate the battery power P.sub.bat charged or discharged during each time step to the capacity and state-of-charge (SOC) of the battery. The capacity constraints may ensure that the SOC of the battery is maintained within acceptable lower and upper bounds and that sufficient battery capacity is available for frequency regulation. In some embodiments, the lower and upper bounds are based on the battery capacity needed to reserve the amount of power

committed to frequency regulation P.sub.FR.sub.i during each time step i.

(165) In some embodiments, capacity constraints module **906** generates two sets of capacity constraints. One set of capacity constraints may apply to the boundary condition at the end of each time step i, whereas the other set of capacity constraints may apply to the boundary condition at the beginning of the next time step i+1. For example, if a first amount of battery capacity is reserved for frequency regulation during time step i and a second amount of battery capacity is reserved for frequency regulation during time step i+1, the boundary point between time step i and i+1 may be required to satisfy the capacity constraints for both time step i and time step i+1. This ensures that the decisions made for the power committed to frequency regulation during the current time step i and the next time step i+1 represent a continuous change in the SOC of the battery.

(166) In some embodiments, capacity constraints module **906** generates the following capacity constraints:

$$(167)\ \left\{\begin{array}{l} C_a - \underset{n=k}{\overset{i}{\text{.Math.}}} P_{\text{bat}_n} \le C_{\text{eff}} - C_{\text{FR}} P_{\text{FR}_i} \\ C_a - \underset{n=k}{\overset{i}{\text{.Math.}}} P_{\text{bat}_n} \ge C_{\text{FR}} P_{\text{FR}_i} \end{array}\right. \quad \forall i = k \text{ .Math. } k+h-1 \left\{\begin{array}{l} C_a - \underset{n=k}{\overset{i}{\text{.Math.}}} P_{\text{bat}_n} \le C_{\text{eff}} - C_{\text{FR}} P_{\text{FR}_{i+1}} \\ C_a - \underset{n=k}{\overset{i}{\text{.Math.}}} P_{\text{bat}_n} \ge C_{\text{FR}} P_{\text{FR}_{i+1}} \end{array}\right. \quad \forall i = k \text{ .Math. } k+h-2$$

where C.sub.a is the available battery capacity (e.g., kWh), C.sub.FR is the frequency regulation reserve capacity (e.g., kWh/kW) which translates the amount of battery power committed to frequency regulation P.sub.FR into an amount of energy needed to be reserved, and C.sub.eff is the effective capacity of the battery.

(168) The first set of constraints ensures that the battery capacity at the end of each time step i (i.e., available capacity C.sub.a minus the battery power discharged through time step i) is maintained between the lower capacity bound C.sub.FRP.sub.FR.sub.i and the upper capacity bound C.sub.eff−C.sub.FR P.sub.FR.sub.i for time step i. The lower capacity bound C.sub.FRP.sub.FR.sub.i represents the minimum capacity required to reserve P.sub.FR.sub.i for frequency regulation during time step i, whereas the upper capacity bound C.sub.eff−C.sub.FRP.sub.FR.sub.i represents maximum capacity required to reserve P.sub.FR.sub.i for frequency regulation during time step i. Similarly, the second set of constraints ensures that the battery capacity at the end of each time step i (i.e., available capacity C.sub.a minus the battery power discharged through time step i) is maintained between the lower capacity bound C.sub.FR P.sub.FR.sub.i+1 and the upper capacity bound C.sub.eff−C.sub.FRP.sub.FR.sub.i+1 for time step i+1. The lower capacity bound C.sub.FRP.sub.FR.sub.i+1 represents the minimum capacity required to reserve P.sub.FR.sub.i+1 for frequency regulation during time step i+1, whereas the upper capacity bound C.sub.eff−C.sub.FRP.sub.FR.sub.i+1 represents maximum capacity required to reserve P.sub.FR.sub.i+1 for frequency regulation during time step i+1.

(169) In some embodiments, capacity constraints module **906** calculates the effective capacity of the battery C.sub.eff as a percentage of the rated capacity of the battery. For example, if frequency regulation and photovoltaic power generation are both enabled and the SOC control margin is non-zero, capacity constraints module **906** can calculate the effective capacity of the battery C.sub.eff using the following equation:

$$(170)\ C_{\text{eff}} = (1 - C_{\text{FR}} - 2C_{\text{socCM}})C_{\text{rated}} C_{\text{PVFirmingReserve}}$$

where C.sub.socCM is the control margin and C.sub.PV Firming Reserve is the capacity reserved for photovoltaic firming.

(171) Still referring to FIG. **9**, high level optimizer **632** is shown to include a switching constraints module **908**. Switching constraints module **908** may be configured to impose one or more switching constraints on the cost function J(x). As previously described, the cost function J(x) may include the following switching term:

$$(172)\ 0 \underset{i=k}{\overset{k+h-1}{\text{.Math.}}} r_{s_i} \text{ .Math. } P_{\text{bat}_i} - P_{\text{bat}_{i-1}} \text{ .Math.}$$

which functions as a penalty for switching the battery power P.sub.bat between consecutive time steps i and i−1. Notably, the switching term is nonlinear as a result of the absolute value function.

(173) Switching constraints module **908** can impose constraints which represent the nonlinear switching term in a linear format. For example, switching constraints module **908** can introduce an auxiliary switching variable s.sub.i and constrain the auxiliary switching variable to be greater than the difference between the battery power P.sub.bat.sub.i at time step i and the battery power P.sub.bat.sub.i−1 at time step i−1, as shown in the following equations:

$$(174)\ \begin{array}{l} s_i > P_{\text{bat}_i} - P_{\text{bat}_{i-1}} \\ s_i > P_{\text{bat}_{i-1}} - P_{\text{bat}_i} \end{array} \quad \forall i = k \text{ .Math. } k+h-1$$

Switching constraints module **908** can replace the nonlinear switching term in the cost function J(x) with the following linearized term:

$$(175)\ \underset{i=k}{\overset{k+h-1}{\text{.Math.}}} r_{s_i} s_i$$

which can be optimized using any of a variety of linear optimization techniques (e.g., linear programming) subject to the constraints on the auxiliary switching variable s.sub.i.

Demand Charge Incorporation

(176) Still referring to FIG. **9**, high level optimizer **632** is shown to include a demand charge module **910**. Demand charge module **910** can be configured to modify the cost function J(x) and the optimization constraints to account for one or more demand charges. As previously described, demand charges are costs imposed by utilities **510** based on the peak consumption of a resource from utilities **510** during various demand charge periods (i.e., the peak amount of the resource purchased from the utility during any time step of the applicable demand charge period). For example, an electric utility may define one or more demand charge periods and may impose a separate demand charge based on the peak electric consumption during each demand charge period. Electric energy storage can help reduce peak consumption by storing electricity in a battery when energy consumption is low and discharging the stored electricity from the battery when energy consumption is high, thereby reducing peak electricity purchased from the utility during any time step of the demand charge period.

(177) In some instances, one or more of the resources purchased from utilities **510** are subject to a demand charge or multiple demand charges. There are many types of potential demand charges as there are different types of energy rate structures. The most common energy rate structures are constant pricing, time of use (TOU), and real time pricing (RTP). Each demand charge may be associated with a demand charge period during which the demand charge is active. Demand charge periods can overlap partially or completely with each other and/or with the optimization period. Demand charge periods can include relatively long periods (e.g., monthly, seasonal, annual, etc.) or relatively short periods (e.g., days, hours, etc.). Each of these periods can be divided into several sub-periods including off-peak, partial-peak, and/or on-peak. Some demand charge periods are continuous (e.g., beginning Jan. 1, 2017 and ending Jan. 31, 2017), whereas other demand charge periods are non-continuous (e.g., from 11:00 AM-1:00 PM each day of the month).

(178) Over a given optimization period, some demand charges may be active during some time steps that occur within the optimization period and inactive during other time steps that occur during the optimization period. Some demand charges may be active over all the time steps that occur within the optimization period. Some demand charges may apply to some time steps that occur during the optimization period and other time steps that occur outside the optimization period (e.g., before or after the optimization period). In some embodiments, the durations of the demand charge periods are significantly different from the duration of the optimization period.

(179) Advantageously, demand charge module **910** may be configured to account for demand charges in the high level optimization process performed by high level optimizer **632**. In some embodiments, demand charge module **910** incorporates demand charges into the optimization problem and the cost function J(x) using demand charge masks and demand charge rate weighting factors. Each demand charge mask may correspond to a particular demand charge and may indicate the time steps during which the corresponding demand charge is active and/or the time

steps during which the demand charge is inactive. Each rate weighting factor may also correspond to a particular demand charge and may scale the corresponding demand charge rate to the time scale of the optimization period.

(180) As described above, the demand charge term of the cost function J(x) can be expressed as:

(181) $J(x) = \text{.Math.}_{s \in \text{sources}} \text{.Math.}_{q \in \text{demands}_s} \text{.Math.} \; w_{\text{demand},s,q} \, r_{\text{demand},s,q} \max_{i \in \text{demand}_{s,q}} (\text{purchase}_{s,i})$ .Math.

where the max( ) function selects the maximum amount of the resource purchased from source s during any time step i that occurs during the optimization period. However, the demand charge period associated with demand charge q may not cover all of the time steps that occur during the optimization period. In order to apply the demand charge q to only the time steps during which the demand charge q is active, demand charge module **910** can add a demand charge mask to the demand charge term as shown in the following equation:

(182) $J(x) = \text{.Math.}_{s \in \text{sources}} \text{.Math.}_{q \in \text{demands}_s} \text{.Math.} \; w_{\text{demand},s,q} \, r_{\text{demand},s,q} \max_{i \in demand_{s,q}} (g_{s,q,i} \, \text{purchase}_{s,i})$ .Math.

where g.sub.s,q,i is an element of the demand charge mask.

(183) The demand charge mask may be a logical vector including an element g.sub.s,q,i for each time step i that occurs during the optimization period. Each element g.sub.s,q,i of the demand charge mask may include a binary value (e.g., a one or zero) that indicates whether the demand charge q for source s is active during the corresponding time step i of the optimization period. For example, the element g.sub.s,q,i may have a value of one (i.e., g.sub.s,q,i=1) if demand charge q is active during time step i and a value of zero (i.e., g.sub.s,q,i=0) if demand charge q is inactive during time step i. An example of a demand charge mask is shown in the following equation:

g.sub.s,q=[0, 0, 0, 1, 1, 1, 1, 0, 0, 0, 1, 1].sup.T

where g.sub.s,q,1, g.sub.s,q,2, g.sub.s,q,3, g.sub.s,q,8, g.sub.s,q,9, and g.sub.s,q,10 have values of zero, whereas g.sub.s,q,4, g.sub.s,q,5, g.sub.s,q,6, g.sub.s,q,7, g.sub.s,q,11, and g.sub.s,q,12 have values of one. This indicates that the demand charge q is inactive during time steps i=1, 2, 3, 8, 9, 10 (i.e., g.sub.s,q,i=0 ∀i=1, 2, 3, 8, 9, 10) and active during time steps i=4, 5, 6, 7, 11, 12 (i.e., g.sub.s,q,i=1 ∀i=4, 5, 6, 7, 11, 12). Accordingly, the term g.sub.s,q,ipurchase.sub.s,i within the max( ) function may have a value of zero for all time steps during which the demand charge q is inactive. This causes the max( ) function to select the maximum purchase from source s that occurs during only the time steps for which the demand charge q is active.

(184) In some embodiments, demand charge module **910** calculates the weighting factor w.sub.demand,s,q for each demand charge q in the cost function J(x). The weighting factor w.sub.demand,s,q may be a ratio of the number of time steps the corresponding demand charge q is active during the optimization period to the number of time steps the corresponding demand charge q is active in the remaining demand charge period (if any) after the end of the optimization period. For example, demand charge module **910** can calculate the weighting factor w.sub.demand,s,q using the following equation:

(185) $w_{\text{demand},s,q} = \dfrac{\text{.Math.}_{i=k}^{k+h-1} g_{s,q,i}}{\text{.Math.}_{i=k+h}^{\text{period_end}} g_{s,q,i}}$

(186) where the numerator is the summation of the number of time steps the demand charge q is active in the optimization period (i.e., from time step k to time step k+h−1) and the denominator is the number of time steps the demand charge q is active in the portion of the demand charge period that occurs after the optimization period (i.e., from time step k+h to the end of the demand charge period). The following example illustrates how demand charge module **910** can incorporate multiple demand charges into the cost function J(x). In this example, a single source of electricity (e.g., an electric grid) is considered with multiple demand charges applicable to the electricity source (i.e., q=1 . . . . N, where N is the total number of demand charges). The system includes a battery asset which can be allocated over the optimization period by charging or discharging the battery during various time steps. Charging the battery increases the amount of electricity purchased from the electric grid, whereas discharging the battery decreases the amount of electricity purchased from the electric grid.

(187) Demand charge module **910** can modify the cost function J(x) to account for the N demand charges as shown in the following equation:

(188)

$$J(x) = \text{.Math.} + w_{d_1} r_{d_1} \max_i(g_{1_i}(-P_{\text{bat}_i} + e\text{Load}_i)) + \text{.Math.} + w_{d_q} r_{d_q} \max_i(g_{q_i}(-P_{\text{bat}_i} + e\text{Load}_i)) + \text{.Math.} + w_{d_N} r_{d_N} \max_i(g_{N_i}(-P_{\text{bat}_i} + e\text{Load}_i))$$

where the term −P.sub.bat.sub.i+eLoad.sub.i represents the total amount of electricity purchased from the electric grid during time step i (i.e., the total electric load eLoad.sub.i minus the power discharged from the battery P.sub.bat.sub.i). Each demand charge q=1 . . . . N can be accounted for separately in the cost function/(x) by including a separate max( ) function for each of the N demand charges. The parameter r.sub.d.sub.q, indicates the demand charge rate associated with the qth demand charge (e.g., $/kW) and the weighting factor w.sub.d.sub.q, indicates the weight applied to the qth demand charge.

(189) Demand charge module **910** can augment each max( ) function with an element g.sub.q.sub.i of the demand charge mask for the corresponding demand charge. Each demand charge mask may be a logical vector of binary values which indicates whether the corresponding demand charge is active or inactive at each time step i of the optimization period. Accordingly, each max( ) function may select the maximum electricity purchase during only the time steps the corresponding demand charge is active. Each max( ) function can be multiplied by the corresponding demand charge rate r.sub.d.sub.q and the corresponding demand charge weighting factor w.sub.d.sub.q to determine the total demand charge resulting from the battery allocation P.sub.bat over the duration of the optimization period.

(190) In some embodiments, demand charge module **910** linearizes the demand charge terms of the cost function J(x) by introducing an auxiliary variable d.sub.q for each demand charge q. In the case of the previous example, this will result in N auxiliary variables d.sub.1 . . . d.sub.N being introduced as decision variables in the cost function J(x). Demand charge module **910** can modify the cost function J(x) to include the linearized demand charge terms as shown in the following equation:

(191) $J(x) = \text{.Math.} + w_{d_1} r_{d_1} d_1 + \text{.Math.} + w_{d_q} r_{d_q} d_q + \text{.Math.} + w_{d_N} r_{d_N} d_N$

(192) Demand charge module **910** can impose the following constraints on the auxiliary demand charge variables d.sub.1 . . . d.sub.N to ensure that each auxiliary demand charge variable represents the maximum amount of electricity purchased from the electric utility during the applicable demand charge period:

(193)

$$\begin{aligned}
&d_1 \geq g_{1_i}(-P_{\text{bat}_i} + e\text{Load}_i) \quad \forall i = k \text{ .Math. } k+h-1, g_{1_i} \neq 0 \\
&\qquad d_1 \geq 0 \qquad \text{.Math.} \\
&d_q \geq g_{q_i}(-P_{\text{bat}_i} + e\text{Load}_i) \quad \forall i = k \text{ .Math. } k+h-1, g_{q_i} \neq 0 \\
&\qquad d_q \geq 0 \qquad \text{.Math.} \\
&d_N \geq g_{N_i}(-P_{\text{bat}_i} + e\text{Load}_i) \quad \forall i = k \text{ .Math. } k+h-1, g_{N_i} \neq 0 \\
&\qquad d_N \geq 0
\end{aligned}$$

(194) In some embodiments, the number of constraints corresponding to each demand charge q is dependent on how many time steps the demand charge q is active during the optimization period. For example, the number of constraints for the demand charge q may be equal to the number of non-zero elements of the demand charge mask g.sub.q. Furthermore, the value of the auxiliary demand charge variable d.sub.q at each iteration of the optimization may act as the lower bound of the value of the auxiliary demand charge variable d.sub.q at the following iteration.

(195) Consider the following example of a multiple demand charge structure. In this example, an electric utility imposes three monthly demand

charges. The first demand charge is an all-time monthly demand charge of 15.86 $/kWh which applies to all hours within the entire month. The second demand charge is an on-peak monthly demand charge of 1.56 $/kWh which applies each day from 12:00-18:00. The third demand charge is a partial-peak monthly demand charge of 0.53 $/kWh which applies each day from 9:00-12:00 and from 18:00-22:00.

(196) For an optimization period of one day and a time step of one hour (i.e., i=1 . . . 24), demand charge module **910** may introduce three auxiliary demand charge variables. The first auxiliary demand charge variable d.sub.1 corresponds to the all-time monthly demand charge; the second auxiliary demand charge variable d.sub.2 corresponds to the on-peak monthly demand charge; and the third auxiliary demand charge variable d.sub.3 corresponds to the partial-peak monthly demand charge. Demand charge module **910** can constrain each auxiliary demand charge variable to be greater than or equal to the maximum electricity purchase during the hours the corresponding demand charge is active, using the inequality constraints described above.

(197) Demand charge module **910** can generate a demand charge mask go for each of the three demand charges (i.e., q=1 . . . 3), where g.sub.q includes an element for each time step of the optimization period (i.e., g.sub.q=[g.sub.q1 . . . g.sub.q24]). The three demand charge masks can be defined as follows:

(198)
$$g_{1_i} = 1 \quad \forall i = 1 \text{ .Math. } 24$$
$$g_{2_i} = 1 \quad \forall i = 12 \text{ .Math. } 18$$
$$g_{3_i} = 1 \quad \forall i = 9 \text{ .Math. } 12, 18 \text{ .Math. } 22$$

with all other elements of the demand charge masks equal to zero. In this example, it is evident that more than one demand charge constraint will be active during the hours which overlap with multiple demand charge periods. Also, the weight of each demand charge over the optimization period can vary based on the number of hours the demand charge is active, as previously described.

(199) In some embodiments, demand charge module **910** considers several different demand charge structures when incorporating multiple demand charges into the cost function J(x) and optimization constraints. Demand charge structures can vary from one utility to another, or the utility may offer several demand charge options. In order to incorporate the multiple demand charges within the optimization framework, a generally-applicable framework can be defined as previously described. Demand charge module **910** can translate any demand charge structure into this framework. For example, demand charge module **910** can characterize each demand charge by rates, demand charge period start, demand charge period end, and active hours. Advantageously, this allows demand charge module **910** to incorporate multiple demand charges in a generally-applicable format.

(200) The following is another example of how demand charge module **910** can incorporate multiple demand charges into the cost function J(x). Consider, for example, monthly demand charges with all-time, on-peak, partial-peak, and off-peak. In this case, there are four demand charge structures, where each demand charge is characterized by twelve monthly rates, twelve demand charge period start (e.g., beginning of each month), twelve demand charge period end (e.g., end of each month), and hoursActive. The hoursActive is a logical vector where the hours over a year where the demand charge is active are set to one. When running the optimization over a given horizon, demand charge module **910** can implement the applicable demand charges using the hoursActive mask, the relevant period, and the corresponding rate.

(201) In the case of an annual demand charge, demand charge module **910** can set the demand charge period start and period end to the beginning and end of a year. For the annual demand charge, demand charge module **910** can apply a single annual rate. The hoursActive demand charge mask can represent the hours during which the demand charge is active. For an annual demand charge, if there is an all-time, on-peak, partial-peak, and/or off-peak, this translates into at most four annual demand charges with the same period start and end, but different hoursActive and different rates.

(202) In the case of a seasonal demand charge (e.g., a demand charge for which the maximum peak is determined over the indicated season period), demand charge module **910** can represent the demand charge as an annual demand charge. Demand charge module **910** can set the demand charge period start and end to the beginning and end of a year. Demand charge module **910** can set the hoursActive to one during the hours which belong to the season and to zero otherwise. For a seasonal demand charge, if there is an All-time, on-peak, partial, and/or off-peak, this translates into at most four seasonal demand charges with the same period start and end, but different hoursActive and different rates.

(203) In the case of the average of the maximum of current month and the average of the maxima of the eleven previous months, demand charge module **910** can translate the demand charge structure into a monthly demand charge and an annual demand charge. The rate of the monthly demand charge may be half of the given monthly rate and the annual rate may be the sum of given monthly rates divided by two. These and other features of demand charge module **910** are described in greater detail in U.S. patent application Ser. No. 15/405,236 filed Jan. 12, 2017, the entire disclosure of which is incorporated by reference herein.

(204) Incentive Program Incorporation

(205) Referring again to FIG. **9**, high level optimizer **632** is shown to include an incentive program module **912**. Incentive program module **912** may modify the optimization problem to account for revenue from participating in an incentive-based demand response (IBDR) program. IBDR programs may include any type of incentive-based program that provides revenue in exchange for resources (e.g., electric power) or a reduction in a demand for such resources. For example, energy storage system **500** may provide electric power to an energy grid or an independent service operator as part of a frequency response program (e.g., PJM frequency response) or a synchronized reserve market. In a frequency response program, a participant contracts with an electrical supplier to maintain reserve power capacity that can be supplied or removed from an energy grid by tracking a supplied signal. The participant is paid by the amount of power capacity required to maintain in reserve. In other types of IBDR programs, energy storage system **500** may reduce its demand for resources from a utility as part of a load shedding program. It is contemplated that energy storage system **500** may participate in any number and/or type of IBDR programs.

(206) In some embodiments, incentive program module **912** modifies the cost function J(x) to include revenue generated from participating in an economic load demand response (ELDR) program. ELDR is a type of IBDR program and similar to frequency regulation. In ELDR, the objective is to maximize the revenue generated by the program, while using the battery to participate in other programs and to perform demand management and energy cost reduction. To account for ELDR program participation, incentive program module **912** can modify the cost function (x) to include the following term:

(207)
$$0 \min_{b_i, P_{bat_i}} \left(- \underset{i=k}{\overset{k+h-1}{\text{.Math.}}} b_i r_{\text{ELDR}_i} (\text{adjCBL}_i - (e\text{Load}_i - P_{\text{bat}_i}))\right)$$

where b.sub.i is a binary decision variable indicating whether to participate in the ELDR program during time step i, r.sub.ELDR.sub.i is the ELDR incentive rate at which participation is compensated, and adjCBL.sub.i is the symmetric additive adjustment (SAA) on the baseline load. The previous expression can be rewritten as:

(208)
$$\min_{b_i, P_{bat_i}} \left(- \underset{i=k}{\overset{k+h-1}{\text{.Math.}}} b_i r_{\text{ELDR}_i} \left(\underset{l=1}{\overset{4}{\text{.Math.}}} \frac{e_{\text{li}}}{4} + \underset{p=m-4}{\overset{m-2}{\text{.Math.}}} \frac{1}{3}(e\text{Load}_p - P_{\text{bat}_p} - \underset{l=1}{\overset{4}{\text{.Math.}}} \frac{e_{\text{lp}}}{4}) - (e\text{Load}_i - P_{\text{bat}_i})\right)\right)$$

where e.sub.li and e.sub.lp are the electric loads at the Ith hour of the operating day.

(209) In some embodiments, incentive program module **912** handles the integration of ELDR into the optimization problem as a bilinear problem with two multiplicative decision variables. In order to linearize the cost function (x) and customize the ELDR problem to the optimization framework, several assumptions may be made. For example, incentive program module **912** can assume that ELDR participation is only in the real-time market, balancing operating reserve charges and make whole payments are ignored, day-ahead prices are used over the horizon, real-time prices are used in calculating the total revenue from ELDR after the decisions are made by the optimization algorithm, and the decision to participate in ELDR is made in advance and passed to the optimization algorithm based on which the battery asset is allocated.

(210) In some embodiments, incentive program module **912** calculates the participation vector b.sub.i as follows:

(211) $b_i = \begin{cases} 1 & \forall i / r_{DA_i} \geq NBT_i \text{ and } i \in S \\ 0 & \text{otherwise} \end{cases}$

where r.sub.DA.sub.i is the hourly day-ahead price at the ith hour, NBT.sub.i is the net benefits test value corresponding to the month to which the corresponding hour belongs, and S is the set of nonevent days. Nonevent days can be determined for the year by choosing to participate every x number of days with the highest day-ahead prices out of y number of days for a given day type. This approach may ensure that there are nonevent days in the 45 days prior to a given event day when calculating the CBL for the event day.

(212) Given these assumptions and the approach taken by incentive program module **912** to determine when to participate in ELDR, incentive program module **912** can adjust the cost function J(x) as follows:

(213) $J(x) = -\text{.Math.}_{i=k}^{k+h-1} r_{e_i} P_{\text{bat}_i} - \text{.Math.}_{i=k}^{k+h-1} r_{\text{FR}_i} P_{\text{FR}_i} + \text{.Math.}_{i=k}^{k+h-1} r_{s_i} s_i + w_d r_d d - \text{.Math.}_{i=k}^{k+h-1} b_i r_{\text{DA}_i} \left(\text{.Math.}_{p=m-4}^{m-2} -\tfrac{1}{3} P_{\text{bat}_p} + P_{\text{bat}_i} \right)$

where b.sub.i and m are known over a given horizon. The resulting term corresponding to ELDR shows that the rates at the ith participation hour are doubled and those corresponding to the SAA are lowered. This means it is expected that high level optimizer **632** will tend to charge the battery during the SAA hours and discharge the battery during the participation hours. Notably, even though a given hour is set to be an ELDR participation hour, high level optimizer **632** may not decide to allocate any of the battery asset during that hour. This is due to the fact that it may be more beneficial at that instant to participate in another incentive program or to perform demand management.

Peak Load Contribution Incorporation

(214) Still referring to FIG. **9**, high level optimizer **632** is shown to include a peak load contribution module **914**. Peak load contribution (PLC) is a customer's contribution to regional demand peaks that occur in geographic area managed by a regional transmission organization (RTO) or independent system operator (ISO) at certain hours within a base period. The regional demand at a given hour may be the summation of the customer's demand during (i.e., the rate at which the customer purchases electricity or another resource from a utility) as well as the demand of other buildings in the geographic area during that hour. The customer may be billed based on its contribution to the peak regional demand (e.g., $/KW of the customer's PLC) in addition to the energy consumption charges and demand charges previously described.

(215) PLC module **914** can be configured to modify the cost function J(x) to account for a cost associated with the customer's PLC. By incorporating PLC costs into the cost function J(x), PLC module **914** enables high level optimizer **632** to allocate resource consumption and resource purchases to reduce the customer's PLC. High level optimizer **632** can reduce PLC costs by shifting the customer's load to non-peak times or shaving the customer's peak load. This can be done, for example, by precooling the building during non-peak times, using thermal energy storage, and/or using electrical energy storage such as a battery asset.

(216) Accounting for the cost associated with the customer's PLC can be more difficult than accounting for energy consumption costs and demand charges. Unlike demand charge which is calculated based on the customer's maximum demand during predetermined demand charge periods, the hours over which PLC is calculated may not be known in advance. The hours of peak regional demand (i.e., the coincidental peak (CP) hours) may not be known until the end of the base period over which PLC is calculated. For example, the CP hours for a given base period (e.g., one year) may be determined by a RTO at the end of the base period based on the demand of all the buildings within the geographic area managed by the RTO during the base period (e.g., by selecting the hours with the highest regional demand). The customer's PLC may then be determined based on the customer's demand during the designated CP hours and used to calculate a cost of the customer's PLC. This cost may then be billed to the customer during the next time period (e.g., the next year), referred to as the billing period.

(217) Another difficulty in accounting for PLC costs is that the base period, billing period, CP hours, and other factors used to calculate the PLC cost may differ from one RTO to another. For example, a RTO for the Pennsylvania, Jersey, and Maryland (PJM) geographic area may define the base period (i.e., the peak-setting period) as June 1.sup.st of year Y to May 31.sup.st of year Y+1. The billing period (i.e., the delivery period) may be defined as June 1.sup.st of year Y+1 to May 31.sup.st of year Y+2. PJM may define the CP hours as the five hours with the highest loads over the five highest peak load days across the PJM geographic region.

(218) A customer's PLC in the PJM region may be calculated as the product of the customer's average electric load during the five CP hours and a capacity loss factor (CLF), as shown in the following equation:

(219) $PLC_{\text{customer}} = \text{CLF} \times \text{.Math.}_{i=1}^{5} \frac{e\text{Load}_{\text{cp}_i}}{5}$

where PLC.sub.customer is the customer's peak load contribution calculated during year Y, CLF is the capacity loss factor (e.g., CLF=1.05), and eLoad.sub.cp.sub.i is the customer's electric load (e.g., kW) during the ith CP hour.

(220) The customer's PLC cost in the PJM region can be calculated as the product of the customer's PLC during year Y and a PLC rate, as shown in the following equation:

PLC.sub.cost=*r*.sub.PLC×PLC.sub.customer

where PLC.sub.cost is the customer's PLC charge billed over the delivery year Y+1 (e.g., $) and r.sub.PLC is the rate at which the customer is charged for its PLC (e.g., $/kW).

(221) An additional complication in the PJM region relates to the interaction between PLC costs and economic load demand response (ELDR) revenue. In some embodiments, a customer participating in ELDR in the PJM region during one of the CP hours may be prohibited from reducing its PLC while earning ELDR revenue at the same time. Accordingly, a customer wishing to reduce its load during an assumed CP hour for the purpose of reducing its capacity, transmission, and/or demand charge costs may be restricted from making a bid for the same assumed CP hour in the ELDR market.

(222) Another example of an organization which imposes PLC costs is the independent electricity system operator (IESO) in Ontario, Canada. Relative to PJM, IESO may use a different base period, billing period, CP hours, and other factors used to calculate the PLC cost. For example, IESO may define the base period or peak-setting period as May 1.sup.st of year Y to April 30.sup.th of year Y+1. The billing period or adjustment period for IESO may be defined as July 1.sup.st of year Y+1 to June 30.sup.th of year Y+2. IESO may define the CP hours as the five hours with the highest regional demands across the IESO geographic region.

(223) At the end of the base period, IESO may calculate the customer's peak demand factor (θ.sub.PDF). The peak demand factor may be defined as the ratio of the sum of the customer's peak demand to the sum of the region-wide demand peaks during the five CP hours, as shown in the following equation:

(224) $\text{PDF} = \frac{\text{.Math.}_{i=1}^{5} e\text{Load}_{\text{cp}_i}}{\text{.Math.}_{i=1}^{5} \text{sysLoad}_{\text{cp}_i}}$

where sysLoad.sub.cp.sub.i is the region-wide peak load during the ith CP hour and eLoad.sub.cp.sub.i is the customer's peak load during the ith CP hour.

(225) The customer's PLC cost in the IESO region is known as a global adjustment (GA) charge. The GA charge may be imposed as a monthly charge during the billing period. In some embodiments, the GA charge is calculated by multiplying the customer's peak demand factor by the monthly region-wide global adjustment costs, as shown in the following equation:

GA.sub.cost,month=θ.sub.PDF×GA.sub.total,month

where GA.sub.cost,month is the customer's monthly PLC cost (e.g., $) and GA.sub.total,month is the region-wide global adjustment cost (e.g., $). The value of GA.sub.total,month may be specified by IESO. In some embodiments, GA.sub.total,month has a known value. In other embodiments,

the value of GA.sub.total,month may not be known until the end of the base period.
(226) In order to incorporate PLC costs into the cost function J(x) and allocate resource consumption/purchases in advance, PLC module **914** can generate or obtain a projection of the CP hours for an upcoming base period. The projected CP hours can then be used by high level optimizer **632** as an estimate of the actual CP hours, for example by applying a peak hours mask (e.g., a peak hours vector) to the PLC term in the cost function J(x), where the peak hours mask is based on the projection of the peak hours for the optimization period. High level optimizer **632** can use the projected CP hours to allocate one or more assets (e.g., a battery, thermal energy storage, HVAC equipment, etc.) to minimize the customer's demand during the projected CP hours. These and other features of PLC module **914** are described in greater detail in U.S. patent application Ser. No. 15/405,234 filed Jan. 12, 2017, the entire disclosure of which is incorporated by reference herein.
(227) Asset Sizing Incorporation
(228) Still referring to FIG. **9**, high level optimizer **632** is shown to include an asset sizing module **916**. Asset sizing module **916** can be configured to determine the optimal sizes of various assets in a building, group of buildings, or a central plant. Assets can include individual pieces of equipment or groups of equipment. For example, assets can include boilers, chillers, heat recovery chillers, steam generators, electrical generators, thermal energy storage tanks, batteries, air handling units, or other types of equipment in a building or a central plant (e.g., HVAC equipment, BMS equipment, etc.). In some embodiments, assets include collections of equipment which form a subplant of a central plant (e.g., central plant **118**). For example, assets can include heater subplant **521**, chiller subplant **522**, heat recovery chiller subplant **523**, steam subplant **524**, electricity subplant **525**, or any other type of generator subplant **520**. In some embodiments, assets include hot thermal energy storage **531** (e.g., one or more hot water storage tanks), cold thermal energy storage **532** (e.g., one or more cold thermal energy storage tanks), electrical energy storage **533** (e.g., one or more batteries), or any other type of storage subplant **530**.
(229) Asset sizes can include a maximum loading of the asset and/or a maximum capacity of the asset. Some assets such as storage subplants **530** may have both a maximum loading and a maximum capacity. For example, battery assets may have a maximum battery power (e.g., a maximum rate at which the battery can be charged or discharged) and a maximum state-of-charge (e.g., a maximum energy storage of the battery). Similarly, thermal energy storage assets may have a maximum charge/discharge rate and a maximum capacity (e.g., maximum fluid storage, etc.). Other assets such as generator subplants **520** may have only a maximum loading. For example, a chiller may have a maximum rate at which the chiller can produce cold thermal energy. Similarly, an electric generator may have a maximum rate at which the generator can produce electricity. Asset sizing module **916** can be configured to determine the maximum loading and/or the maximum capacity of an asset when determining the optimal size of the asset.
(230) In some embodiments, asset sizing module **916** is implemented a component of planning tool **702**. In the planning tool framework, asset sizing module **916** can determine the optimal size of an asset for a given application. For example, consider the planning problem described with reference to FIGS. **7-8** in which the high level optimization is solved at a given time instant k over a given time horizon h. With each iteration of the high level optimization, the time horizon h can be shifted forward by a block size equivalent to b time steps and the first b sets of decision variables may be retained. In such a planning problem, the sizes of the assets to be optimally allocated are typically given along with historical load data, utility pricing, and other relative data. However, there are many cases in which the sizes of the assets to be allocated are unknown. For example, when purchasing a new asset for a given application (e.g., adding thermal energy storage or electrical energy storage to a building or central plant), a user may wish to determine the optimal size of the asset to purchase.
(231) Asset sizing module **916** can be configured to determine the optimal size of an asset by considering the potential benefits and costs of the asset. Potential benefits can include, for example, reduced energy costs, reduced demand charges, reduced PLC charges, and/or increased revenue from participating in IBDR programs such as frequency regulation (FR) or economic load demand response (ELDR), including revenue as part of a capacity market program. Potential costs can include fixed costs (e.g., an initial purchase cost of the asset) as well as marginal costs (e.g., ongoing costs of using the asset) over the time horizon. The potential benefits and costs of an asset may vary based on the application of the asset and/or the system in which the asset will be used. For example, a system that participates in FR programs may realize the benefit of increased IBDR revenue, whereas a system that does not participate in any IBDR programs may not realize such a benefit.
(232) Some of the benefits and costs of an asset may be captured by the original cost function J(x). For example, the cost function J(x) may include terms corresponding to energy cost, multiple demand charges, PLC charges, and/or IBDR revenue, as previously described. Adding one or more new assets may affect the values of some or all of these terms in the original cost function J(x). For example, adding a battery asset may increase IBDR revenue and decrease energy cost, demand charges, and PLC charges. However, the original cost function J(x) may not account for the fixed and marginal costs resulting from new asset purchases. In order to account for these fixed and marginal costs, asset sizing module **916** may add new terms to the original cost function J(x).
(233) Asset sizing module **916** can be configured to augment the cost function J(x) with two new terms that correspond to the cost of purchasing the new assets, resulting in an augmented cost function J.sub.a(x). The additional terms are shown in the following equation:
J.sub.a(*x*)=*J*(*x*)+*c*.sub.f.sup.T*v*+*c*.sub.s.sup.T*s*.sub.a
where J(x) is the original cost function, x is the vector of decision variables of the optimization problem over the horizon, c.sub.f is a vector of fixed costs of buying any size of asset (e.g., one element for each potential asset purchase), v is a vector of binary decision variables that indicate whether the corresponding assets are purchased, c.sub.s is a vector of marginal costs per unit of asset size (e.g., cost per unit loading, cost per unit capacity), and s.sub.a is a vector of continuous decision variables corresponding to the asset sizes. Advantageously, the binary purchase decisions and asset size decisions are treated as decision variables which can be optimized along with the decision variables in the vector x. This allows high level optimizer **632** to perform a single optimization to determine optimal values for all of the decision variables in the augmented cost function J.sub.a(x).
(234) In some embodiments, asset sizing module **916** scales the asset purchase costs c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a to the duration of the optimization period h. The cost of purchasing an asset is typically paid over an entire payback period SPP, whereas the operational cost is only over the optimization period h. In order to scale the asset purchase costs to the optimization period, asset sizing module **916** can multiply the terms c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a by the ratio h/SPP as SPP shown in the following equation:
(235) $J_a(x) = J(x) + \frac{h}{8760\ .\text{Math.}\ SPP}(c_f^T v + c_s^T s_a)$
where h is the duration of the optimization period in hours, SPP is the duration of the payback period in years, and 8760 is the number of hours in a year.
(236) High level optimizer **632** can perform an optimization process to determine the optimal values of each of the binary decision variables in the vector v and each of the continuous decision variables in the vector s.sub.a. In some embodiments, high level optimizer **632** uses linear programming (LP) or mixed integer linear programming (MILP) to optimize a financial metric such as net present value (NPV), simple payback period (SPP), or internal rate of return (IRR). Each element of the vectors c.sub.f, v, c.sub.s, and s.sub.a may correspond to a particular asset and/or a particular asset size. Accordingly, high level optimizer **632** can determine the optimal assets to purchase and the optimal sizes to purchase by identifying the optimal values of the binary decision variables in the vector v and the continuous decision variables in the vector s.sub.a. These and other features of asset sizing module **916** are described in greater detail with reference to FIG. **10**.
(237) Subplant Curve Incorporation
(238) Still referring to FIG. **9**, high level optimizer **632** is shown to include a subplant curves module **930**. In the simplest case, it can be assumed that the resource consumption of each subplant is a linear function of the thermal energy load produced by the subplant. However, this assumption may not be true for some subplant equipment, much less for an entire subplant. Subplant curves module **930** may be configured to modify the high level optimization problem to account for subplants that have a nonlinear relationship between resource consumption and load production.

(239) Subplant curves module **930** is shown to include a subplant curve updater **932**, a subplant curves database **934**, a subplant curve linearizer **936**, and a subplant curves incorporator **938**. Subplant curve updater **932** may be configured to request subplant curves for each of subplants **520**-**530** from low level optimizer **634**. Each subplant curve may indicate an amount of resource consumption by a particular subplant (e.g., electricity use measured in kW, water use measured in L/s, etc.) as a function of the subplant load.
(240) In some embodiments, low level optimizer **634** generates the subplant curves by running the low level optimization process for various combinations of subplant loads and weather conditions to generate multiple data points. Low level optimizer **634** may fit a curve to the data points to generate the subplant curves and provide the subplant curves to subplant curve updater **832**. In other embodiments, low level optimizer **634** provides the data points to subplant curve updater **932** and subplant curve updater **932** generates the subplant curves using the data points. Subplant curve updater **932** may store the subplant curves in subplant curves database **934** for use in the high level optimization process.
(241) In some embodiments, the subplant curves are generated by combining efficiency curves for individual devices of a subplant. A device efficiency curve may indicate the amount of resource consumption by the device as a function of load. The device efficiency curves may be provided by a device manufacturer or generated using experimental data. In some embodiments, the device efficiency curves are based on an initial efficiency curve provided by a device manufacturer and updated using experimental data. The device efficiency curves may be stored in equipment models **618**. For some devices, the device efficiency curves may indicate that resource consumption is a U-shaped function of load. Accordingly, when multiple device efficiency curves are combined into a subplant curve for the entire subplant, the resultant subplant curve may be a wavy curve. The waves are caused by a single device loading up before it is more efficient to turn on another device to satisfy the subplant load.
(242) Subplant curve linearizer **936** may be configured to convert the subplant curves into convex curves. A convex curve is a curve for which a line connecting any two points on the curve is always above or along the curve (i.e., not below the curve). Convex curves may be advantageous for use in the high level optimization because they allow for an optimization process that is less computationally expensive relative to an optimization process that uses non-convex functions. Subplant curve linearizer **936** may be configured to break the subplant curves into piecewise linear segments that combine to form a piecewise-defined convex curve. Subplant curve linearizer **936** may store the linearized subplant curves in subplant curves database **934**.
(243) Subplant curve incorporator **938** may be configured to modify the high level optimization problem to incorporate the subplant curves into the optimization. In some embodiments, subplant curve incorporator **938** modifies the decision variables to include one or more decision vectors representing the resource consumption of each subplant. Subplant curve incorporator **938** may modify the inequality constraints to ensure that the proper amount of each resource is consumed to serve the predicted thermal energy loads. In some embodiments, subplant curve incorporator **938** formulates inequality constraints that force the resource usage for each resource in the epigraph of the corresponding linearized subplant curve. For example, chiller subplant **522** may have a linearized subplant curve that indicates the electricity use of chiller subplant **522** (i.e., input resource in.sub.1) as a function of the cold water production of chiller subplant **522** (i.e., output resource out.sub.1). The linearized subplant curve may include a first line segment connecting point [u.sub.1, Q.sub.1] to point [u.sub.2, Q.sub.2], a second line segment connecting point [u.sub.2, Q.sub.2] to point [u.sub.3, Q.sub.3], and a third line segment connecting point [u.sub.3, Q.sub.3] to point [u.sub.4, Q.sub.4].
(244) Subplant curve incorporator **938** may formulate an inequality constraint for each piecewise segment of the subplant curve that constrains the value of the decision variable representing chiller electricity use to be greater than or equal to the amount of electricity use defined by the line segment for the corresponding value of the cold water production. Similar inequality constraints can be formulated for other subplant curves. For example, subplant curve incorporator **938** may generate a set of inequality constraints for the water consumption of chiller subplant **522** using the points defining the linearized subplant curve for the water consumption of chiller subplant **522** as a function of cold water production. In some embodiments, the water consumption of chiller subplant **522** is equal to the cold water production and the linearized subplant curve for water consumption includes a single line segment connecting point [u.sub.5, Q.sub.5] to point [u.sub.6, Q.sub.6]. Subplant curve incorporator **938** may repeat this process for each subplant curve for chiller subplant **522** and for the other subplants of the central plant to define a set of inequality constraints for each subplant curve.
(245) The inequality constraints generated by subplant curve incorporator **938** ensure that high level optimizer **632** keeps the resource consumption above all of the line segments of the corresponding subplant curve. In most situations, there is no reason for high level optimizer **632** to choose a resource consumption value that lies above the corresponding subplant curve due to the economic cost associated with resource consumption. High level optimizer **632** can therefore be expected to select resource consumption values that lie on the corresponding subplant curve rather than above it.
(246) The exception to this general rule is heat recovery chiller subplant **523**. The equality constraints for heat recovery chiller subplant **523** provide that heat recovery chiller subplant **523** produces hot water at a rate equal to the subplant's cold water production plus the subplant's electricity use. The inequality constraints generated by subplant curve incorporator **938** for heat recovery chiller subplant **523** allow high level optimizer **632** to overuse electricity to make more hot water without increasing the amount of cold water production. This behavior is extremely inefficient and only becomes a realistic possibility when the demand for hot water is high and cannot be met using more efficient techniques. However, this is not how heat recovery chiller subplant **523** actually operates.
(247) To prevent high level optimizer **632** from overusing electricity, subplant curve incorporator **938** may check whether the calculated amount of electricity use (determined by the optimization algorithm) for heat recovery chiller subplant **523** is above the corresponding subplant curve. In some embodiments, the check is performed after each iteration of the optimization algorithm. If the calculated amount of electricity use for heat recovery chiller subplant **523** is above the subplant curve, subplant curve incorporator **938** may determine that high level optimizer **632** is overusing electricity. In response to a determination that high level optimizer **632** is overusing electricity, subplant curve incorporator **938** may constrain the production of heat recovery chiller subplant **523** at its current value and constrain the electricity use of subplant **523** to the corresponding value on the subplant curve. High level optimizer **632** may then rerun the optimization with the new equality constraints. These and other features of subplant curves module **930** are described in greater detail in U.S. patent application Ser. No. 14/634,609 filed Feb. 27, 2015, the entire disclosure of which is incorporated by reference herein.
(248) Asset Sizing Module
(249) Referring now to FIG. **10**, a block diagram illustrating asset sizing module **916** in greater detail is shown, according to an exemplary embodiment. Asset sizing module **916** can be configured to determine the optimal sizes of various assets in a building, group of buildings, or a central plant. As described above, assets can include individual pieces of equipment (e.g., boilers, chillers, heat recovery chillers, steam generators, electrical generators, thermal energy storage tanks, batteries, etc.), groups of equipment, or entire subplants of a central plant. Asset sizes can include a maximum loading of the asset (e.g., maximum power, maximum charge/discharge rate) and/or a maximum capacity of the asset (e.g., maximum stored electric energy, maximum fluid storage, etc.).
(250) In some embodiments, asset sizing module **916** includes a user interface generator **1006**. User interface generator **1006** can be configured to generate a user interface for interacting with asset sizing module **916**. The user interface may be provided to a user device **1002** (e.g., a computer workstation, a laptop, a tablet, a smartphone, etc.) and presented via a local display of user device **1002**. In some embodiments, the user interface prompts a user to select one or more assets or types of assets to be sized. The selected assets can include assets currently in a building or central plant (e.g., existing assets the user is considering upgrading or replacing) or new assets not currently in the building or central plant (e.g., new assets the user is considering purchasing). For example, if the user is considering adding thermal energy storage or electrical energy storage to a building or central plant, the user may select “thermal energy storage” or “battery” from a list of potential assets to size/evaluate. User interface generator **1006** can identify any assets selected via the user interface and provide an indication of the selected assets to asset cost term generator **1008**.
(251) Asset cost term generator **1008** can be configured to generate one or more cost terms representing the purchase costs of the assets being sized.

In some embodiments, asset cost term generator **1008** generates the following two asset cost terms:
c.sub.f.sup.T*v*+*c*.sub.s.sup.Ts.sub.a
where c.sub.f is a vector of fixed costs of buying any size of asset (e.g., one element for each potential asset purchase), v is a vector of binary decision variables that indicate whether the corresponding assets are purchased, c.sub.s is a vector of marginal costs per unit of asset size (e.g., cost per unit loading, cost per unit capacity), and s.sub.a is a vector of continuous decision variables corresponding to the asset sizes. Advantageously, the binary purchase decisions in vector v and asset size decisions in vector s.sub.a can be treated as decision variables to be optimized along with other decision variables x in the augmented cost function J.sub.a(x), described in greater detail below.
(252) It should be noted that the values of the binary decision variables in vector v and the continuous decision variables in vector s.sub.a indicate potential asset purchases and asset sizes which can be evaluated by asset sizing module **916** to determine whether such purchases/sizes optimize a given financial metric. The values of these decision variables can be adjusted by asset sizing module **916** as part of an optimization process and do not necessarily reflect actual purchases or a current set of assets installed in a building, set of buildings, or central plant. Throughout this disclosure, asset sizing module **916** is described as "purchasing" various assets or asset sizes. However, it should be understood that these purchases are merely hypothetical. For example, asset sizing module **916** can "purchase" an asset by setting the binary decision variable v.sub.j for the asset to a value of v.sub.j=1. This indicates that the asset is considered purchased within a particular hypothetical scenario and the cost of the asset is included in the augmented cost function J.sub.a(x). Similarly, asset sizing module **916** can choose to not purchase an asset by setting the binary decision variable v.sub.j for the asset to a value of v.sub.j=0. This indicates that the asset is considered not purchased within a particular hypothetical scenario and the cost of the asset is not included in the augmented cost function J.sub.a(x).
(253) The additional cost terms c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a can be used to account for the purchase costs of any number of new assets. For example, if only a single asset is being sized, the vector c.sub.f may include a single fixed cost (i.e., the fixed cost of buying any size of the asset being considered) and v may include a single binary decision variable indicating whether the asset is purchased or not purchased (i.e., whether the fixed cost is incurred). The vector c.sub.s may include a single marginal cost element and s.sub.a may include a single continuous decision variable indicating the size of the asset to purchase. If the asset has both a maximum loading and a maximum capacity (i.e., the asset is a storage asset), the vector c.sub.s may include a first marginal cost per unit loading and a second marginal cost per unit capacity. Similarly, the vector s.sub.a may include a first continuous decision variable indicating the maximum loading size to purchase and a second continuous decision variable indicating the maximum capacity size to purchase.
(254) If multiple assets are being sized, the vectors c.sub.f, v, c.sub.s, and s.sub.a may include elements for each asset. For example, the vector c.sub.f may include a fixed purchase cost for each asset being sized and v may include a binary decision variable indicating whether each asset is purchased. The vector c.sub.s may include a marginal cost element for each asset being considered and s.sub.a may include a continuous decision variable indicating the size of each asset to purchase. For any asset that has both a maximum loading and a maximum capacity, the vector c.sub.s may include multiple marginal cost elements (e.g., a marginal cost per unit loading size and a marginal cost per unit capacity size) and the vector s.sub.a may include multiple continuous decision variables (e.g., a maximum loading size to purchase and a maximum capacity size to purchase). By accounting for the purchase costs of multiple assets in terms of their respective sizes, the cost terms c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a allow high level optimizer **632** to optimize multiple asset sizes concurrently.
(255) Still referring to FIG. **10**, asset sizing module **916** is shown to include a constraints generator **1010**. Constraints generator **1010** can be configured to generate or update the constraints on the optimization problem. As discussed above, the constraints prevent high level optimizer **632** from allocating a load to an asset that exceeds the asset's maximum loading. For example, the constraints may prevent high level optimizer **632** from allocating a cooling load to a chiller that exceeds the chiller's maximum cooling load or assigning a power setpoint to a battery that exceeds the battery's maximum charge/discharge rate. The constraints may also prevent high level optimizer **632** from allocating resources in a way that causes a storage asset to exceed its maximum capacity or deplete below its minimum capacity. For example, the constraints may prevent high level optimizer **632** from charging a battery or thermal energy storage tank above its maximum capacity or discharging below its minimum stored electric energy (e.g., below zero).
(256) When asset sizes are fixed, the loading constraints can be written as follows:
(257) $x_{j,i,\text{load}} \leq x_{j,\text{load}_{max}} \quad \forall j = 1 \text{ .Math. } N_a \quad \forall i = k \text{ .Math. } k + h - 1$
(258) where x.sub.j,i,load is the load on asset j at time step i over the horizon, x.sub.j,load.sub.max is the fixed maximum load of the asset j, and N.sub.a is the total number of assets. Similarly, the capacity constraints can be written as follows:
(259) $0 \leq x_{j,i,\text{cap}} \leq x_{j,i,\text{cap}_{\max}} \quad \forall j = 1 \text{ .Math. } N_a \quad \forall i = k \text{ .Math. } k + h - 1$
where x.sub.j,i,cap is the capacity of asset j at time step i over the horizon and x.sub.j,cap.sub.max is the fixed maximum capacity of the asset j. However, these constraints assume that the maximum load x.sub.j,load.sub.max and maximum capacity x.sub.j,cap.sub.max of an asset is fixed. When asset sizes are treated as optimization variables, the maximum load and capacity of an asset may be a function of the asset size purchased in the optimization problem (i.e., the size of the asset defined by the values of the binary and continuous decision variables in vectors v and s.sub.a).
(260) Constraints generator **1010** can be configured to update the loading constraints to accommodate a variable maximum loading for each asset being sized. In some embodiments, constraints generator **1010** updates the loading constraints to limit the maximum load of an asset to be less than or equal to the total size of the asset purchased in the optimization problem. For example, constraints generator **1010** can translate the loading constraints into the following:
(261) $$\begin{aligned} x_{j,i,\text{load}} &\leq s_{a_{j,\text{load}}} \\ s_{a_{j,\text{load}}} &\leq M_j v_j \end{aligned} \quad \forall j = 1 \text{ .Math. } N_a$$
where s.sub.a.sub.j,load is the loading size of asset j (i.e., the jth load size element of the continuous variable vector s.sub.a), v.sub.j is the binary decision variable indicating whether asset j is purchased (i.e., the jth element of the binary variable vector v), and M.sub.j is a sufficiently large number. In some embodiments, the number M.sub.j is set to the largest size of asset j that can be purchased. The first inequality in this set of constraints ensures that the load on an asset x.sub.j,i,load is not greater than the size of the asset s.sub.a.sub.j,load that is purchased. The second inequality forces the optimization to pay for the fixed cost of an asset before increasing the load size of the asset. In other words, asset j must be purchased (i.e., v.sub.j=1) before the load size s.sub.a.sub.j,load of asset j can be increased to a non-zero value.
(262) Similarly, constraints generator **1010** can be configured to update the capacity constraints to accommodate a variable maximum capacity for each storage asset being sized. In some embodiments, constraints generator **1010** updates the capacity constraints to limit the capacity of an asset between zero and the total capacity of the asset purchased in the optimization problem. For example, constraints generator **1010** can translate the capacity constraints into the following:
(263) $$\begin{aligned} 0 \leq x_{j,i,\text{cap}} &\leq s_{a_j,\text{cap}} \\ s_{a_{j,\text{cap}}} &\leq M_j v_j \end{aligned} \quad \forall j = 1 \text{ .Math. } N_a$$
where s.sub.a.sub.j,cap is the capacity size of asset j (i.e., the jth capacity size element of the continuous variable vector s.sub.a), v.sub.j is the binary decision variable indicating whether asset j is purchased (i.e., the jth element of the binary variable vector v), and M.sub.j is a sufficiently large number. In some embodiments, the number M.sub.j is set to the largest size of asset j that can be purchased. The first inequality in this set of

constraints ensures that the capacity of an asset x.sub.j,i,cap at any time step i is between zero and the capacity size of the asset s.sub.a.sub.j,cap that is purchased. The second inequality forces the optimization to pay for the fixed cost of an asset before increasing the capacity size of the asset. In other words, asset j must be purchased (i.e., v.sub.j=1) before the capacity size s.sub.a.sub.j,cap of asset j can be increased to a non-zero value.

(264) The constraints generated or updated by constraints generator **1010** may be imposed on the optimization problem along with the other constraints generated by high level optimizer **632**. In some embodiments, the loading constraints generated by constraints generator **1010** replace the power constraints generated by power constraints module **904**. Similarly, the capacity constraints generated by constraints generator **1010** may replace the capacity constraints generated by capacity constraints module **906**. However, the asset loading constraints and capacity constraints generated by constraints generator **1010** may be imposed in combination with the switching constraints generated by switching constraints module **908**, the demand charge constraints generated by demand charge module **910**, and any other constraints imposed by high level optimizer **632**.

(265) Still referring to FIG. **10**, asset sizing module **916** is shown to include a scaling factor generator **1012**. The cost of purchasing an asset is typically paid over the duration of a payback period, referred to herein as a simple payback period (SPP). However, the original cost function J(x) may only capture operational costs and benefits over the optimization period h, which is often much shorter than the SPP. In order to combine the asset purchase costs c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a with the original cost function J(x), it may be necessary to place the costs on the same time scale.

(266) In some embodiments, scaling factor generator **1012** generates a scaling factor for the asset cost terms c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a. The scaling factor can be used to scale the asset purchase costs c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a to the duration of the optimization period h. For example, scaling factor generator **1012** can multiply the terms c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a by the ratio h/SPP shown in the following equation:

(267) $C_{\text{scaled}} = \frac{h}{8760 \text{ .Math. } SPP}(c_f^T v + c_s^T s_a)$

where C.sub.scaled is the purchase cost of the assets scaled to the optimization period, h is the duration of the optimization period in hours, SPP is the duration of the payback period in years, and 8760 is the number of hours in a year.

(268) In other embodiments, scaling factor generator **1012** generates a scaling factor for the original cost function J(x). The scaling factor can be used to extrapolate the original cost function J(x) to the duration of the simple payback period SPP. For example, scaling factor generator **1012** can multiply the original cost function J(x) by the ratio SPP/h as shown in the following equation:

(269) $J(x)_{\text{scaled}} = \frac{8760 \text{ .Math. } SPP}{h} J(x)$

where J(x).sub.scaled is the scaled cost function extrapolated to the duration of the simple payback period SPP, h is the duration of the optimization period in hours, SPP is the duration of the payback period in years, and 8760 is the number of hours in a year.

(270) Still referring to FIG. **10**, asset sizing module **916** is shown to include a cost function augmenter **1014**. Cost function augmenter **1014** can be configured to augment the original cost function J(x) with the scaled purchase cost of the assets C.sub.scaled. The result is an augmented cost function J.sub.a(x) as shown in the following equation:

(271) $J_a(x) = J(x) + \frac{h}{8760 \text{ .Math. } SPP}(c_f^T v + c_s^T s_a)$

where h is the duration of the optimization period in hours, SPP is the duration of the payback period in years, and 8760 is the number of hours in a year.

(272) High level optimizer **632** can perform an optimization process to determine the optimal values of each of the binary decision variables in the vector v and each of the continuous decision variables in the vector s.sub.a. In some embodiments, high level optimizer **632** uses linear programming (LP) or mixed integer linear programming (MILP) to optimize a financial metric such as net present value (NPV), simple payback period (SPP), or internal rate of return (IRR). Each element of the vectors c.sub.f, v, c.sub.s, and s.sub.a may correspond to a particular asset and/or a particular asset size. Accordingly, high level optimizer **632** can determine the optimal assets to purchase and the optimal sizes to purchase by identifying the optimal values of the binary decision variables in the vector v and the continuous decision variables in the vector s.sub.a.

(273) Still referring to FIG. **10**, asset sizing module **916** is shown to include a benefit curve generator **1016**. Benefit curve generator **1016** can be configured to generate a benefit curve based on the augmented cost function J.sub.a(x). In some embodiments, the benefit curve indicates the relationship between the initial investment cost C.sub.0 of an asset (i.e., the cost of purchasing the asset) and the annual benefit C derived from the asset. For example, the benefit curve may express the initial investment cost C.sub.0 as a function of the annual benefit C, as shown in the following equation:

C.sub.0=*f*(*C*)

where both the initial investment cost C.sub.0 and the annual benefit C are functions of the asset size. Several examples of benefit curves which can be generated by benefit curve generator **1016** are shown in FIGS. **12-15** (discussed in greater detail below).

(274) In some embodiments, the initial investment cost C.sub.0 is the term c.sub.f.sup.Tv+c.sub.s.sup.Ts.sub.a in the augmented cost function J.sub.a(x). The benefit of an asset over the optimization horizon h may correspond to the term J(x) in the augmented cost function J.sub.a(x) and may be represented by the variable C.sub.h. In some embodiments, the variable C.sub.h represents the difference between a first value of J(x) when the asset is not included in the optimization and a second value of J(x) when the asset is included in the optimization. The annual benefit C can be found by extrapolating the benefit over the horizon C.sub.h to a full year. For example, the benefit over the horizon C.sub.h can be scaled to a full year as shown in the following equation:

(275) $C = \frac{8760}{h} C_h$

where h is the duration of the optimization horizon in hours and 8760 is the number of hours in a year.

(276) Increasing the size of an asset increases both its initial cost C.sub.0 and the annual benefit C derived from the asset. However, the benefit C of an asset will diminish beyond a certain asset size or initial asset cost C.sub.0. In other words, choosing an asset with a larger size will not yield any increased benefit. The benefit curve indicates the relationship between C.sub.0 and C and can be used to find the asset size that optimizes a given financial metric (e.g., SPP, NPV, IRR, etc.). Several examples of such an optimization are described in detail below. In some embodiments, benefit curve generator **1016** provides the benefit curve to financial metric optimizer **1020** for use in optimizing a financial metric.

(277) Still referring to FIG. **10**, asset sizing module **916** is shown to include a financial metric optimizer **1020**. Financial metric optimizer **1020** can be configured to find an asset size that optimizes a given financial metric. The financial metric may be net present value (NPV), internal rate of return (IRR), simple payback period (SPP), or any other financial metric which can be optimized as a function of asset size. In some embodiments, the financial metric to be optimized is selected by a user. For example, the user interface generated by user interface generator **1006** may prompt the user to select the financial metric to be optimized. In other embodiments, asset sizing module **916** may automatically determine the financial metric to be optimized or may optimize multiple financial metrics concurrently (e.g., running parallel optimization processes).

(278) Net Present Value Optimization

(279) Financial metric optimizer **1020** is shown to include a net present value (NPV) optimizer **1022**. NPV optimizer **1022** can be configured to find an asset size that optimizes the net present value of the system in which the asset will be used. The NPV of a system can be calculated as shown below:

NPV=NPV.sub.asset−*C*.sub.0

where NPV is the net present value of the system, NPV.sub.asset is the net present value of the asset, and C.sub.0 is the initial purchase cost of the asset. In some embodiments, the NPV of the asset is an annuity which can be calculated as follows:

(280) $NPV_{\text{asset}} = \underset{t=1}{\overset{N}{\text{.Math.}}} \frac{C_t}{(1+r)^t}$

where r is the interest rate, C.sub.t is the benefit or cash flow of the system in year t, and N is the total number of financial years or life-cycle of the system.

(281) In some embodiments, the annual benefit of the system is constant over its life cycle. Accordingly, the annual benefit C may be equivalent to the benefit C.sub.t, as shown in the following equation:

C.sub.t=$C\forall t$

This allows the annuity NPV.sub.asset to be expressed as follows:

NPV.sub.asset=$a(r,N)C$

where a(r, N) is the annuity factor. The annuity factor a(r, N) may be the sum of a geometric sequence having the following expression:

(282) $a(r,N) = \frac{1-(1+r)^{-N}}{r}$

(283) The annuity NPV.sub.asset represents the net present value of the annual benefit over the life-cycle of the system. FIG. **11** shows a graph **1100** of the annuity factor a(r, N) as a function of the interest rate r for several system life-cycles. In graph **1100**, line **1116** corresponds to a system life-cycle of one year (N=1), line **1114** corresponds to a system life-cycle of two years (N=2), line **1112** corresponds to a system life-cycle of three years (N=3), line **1110** corresponds to a system life-cycle of five years (N=5), line **1108** corresponds to a system life-cycle of ten years (N=10), line **1106** corresponds to a system life-cycle of fifteen years (N=15), line **1104** corresponds to a system life-cycle of twenty years (N=20), and line **1102** corresponds to a system life-cycle of thirty years (N=30). For a given system life-cycle, the annuity factor a(r, N) is generally a decreasing function of the interest rate r. If the inverse of the interest rate r is much less than the life-cycle of the system

(284) $(i.e., \frac{1}{r} \ll N)$,

the annuity factor a(r, N) can be approximated by 1/r.

(285) By substituting NPV.sub.asset=a(r, N)C into the equation for the net present value of the system, the net present value of the system can be written as follows:

NPV=$a(r,N)C-C$.sub.0

where C is the annual benefit of the asset and C.sub.0 is the initial purchase cost of the asset. As discussed above, the initial investment cost C.sub.0 may be equivalent to the term c.sub.f.sup.Tv+c.sub.s.sup.Ts.sub.a in the augmented cost function J.sub.a(x). The benefit of an asset over the optimization horizon h may correspond to the term J(x) in the augmented cost function J.sub.a(x) and may be represented by the variable C.sub.h. The annual benefit C can be found by extrapolating the benefit over the horizon C.sub.h to a full year. For example, the benefit over the horizon C.sub.h can be scaled to a full year as shown in the following equation:

(286) $C = \frac{8760}{h}C_h$

where h is the duration of the optimization horizon in hours and 8760 is the number of hours in a year. Accordingly, the net present value of the system can be written as follows:

(287) $NPV = \frac{8760\ .\text{Math.}\ a(r,N)}{h}C_h - (c_f^T v + c_s^T s_a)$

(288) In some embodiments, NPV optimizer **1022** scales the net present value of the system NPV to the duration of the optimization period h. For example, NPV optimizer **1022** can divide the previous equation for NPV by the factor

(289) $0\frac{8760\ .\text{Math.}\ a(r,N)}{h}$

and replace C.sub.h with the original cost function J(x). This results in the following expression for the augmented cost function J.sub.a(x):

(290) $J_a(x) = J(x) + \frac{h}{8760\ .\text{Math.}\ a(r,N)}(c_f^T v + c_s^T s_a)$

which is similar to the other expression of the augmented cost function J.sub.a(x) previously described:

(291) $J_a(x) = J(x) + \frac{h}{8760\ .\text{Math.}\ \text{SPP}}(c_f^T v + c_s^T s_a)$

The first expression for J.sub.a(x) includes the annuity factor a(r, N) in the denominator of the factor weighting the asset cost, whereas the second expression for J.sub.a(x) includes the target simple payback period SPP. This similarity indicates that the annuity factor a(r, N) plays an important role in the optimization of a financial metric as a function of asset size.

(292) As discussed above, the net present value of a system NPV can be expressed by the equation:

(293) $NPV = a(r,N)C - C_0$

which can be rearranged as follows:

(294) $C_0 = a(r,N)C - NPV$

This equation for C.sub.0 can be plotted as a straight line with a slope equal to the annuity factor a(r, N) and a y-intercept equal to the negative net present value −NPV. Several examples of such plots are shown in FIGS. **12-14**.

(295) Referring now to FIG. **12** a graph **1200** of initial investment cost C.sub.0 as a function of annual benefit C is shown, according to an exemplary embodiment. Graph **1200** is shown to include a benefit curve **1202**. Benefit curve **1202** is an example of a benefit curve for an asset or collection of assets being sized. In some embodiments, benefit curve **1202** is generated by benefit curve generator **1016**, as previously described. Increasing the size of an asset increases both its initial cost C.sub.0 and the annual benefit C derived from the asset. However, the annual benefit C of an asset may approach a limit (e.g., a vertical asymptote in graph **1200**) as the asset size or initial investment cost C.sub.0 continues to increase. This effect can be seen in the curvature of benefit curve **1202**. As the initial investment cost C.sub.0 increases, the corresponding changes in the annual benefit C diminish and eventually become insignificant.

(296) Graph **1200** is shown to include two linear lines **1204** and **1206**. Both lines **1204** and **1206** have the form C.sub.0=a(r, N)C−NPV, where a(r, N) is the slope and −NPV is the y-intercept. For example, line **1206** has a slope of a.sub.1(r.sub.1, N.sub.1), which is the annuity factor defined by a first interest rate r.sub.1 and a first system life-cycle N.sub.1. Line **1206** intersects the y-axis at point **1208**, which corresponds to the negative net present value of the system −NPV.sub.1. Similarly, line **1204** has a slope of a.sub.2(r.sub.2, N.sub.2), which corresponds to an annuity factor defined by a second interest rate r.sub.2 and a second system life-cycle N.sub.2. Line **1204** intersects the y-axis at point **1208**, which corresponds to the negative net present value of the system −NPV.sub.2.

(297) Graph **1200** is shown to include an intersection point **1212**. Point **1212** is the point at which line **1204** intersects benefit curve **1202**. Intersection point **1212** is a feasible solution to the NPV optimization given the annuity factor a.sub.2(r.sub.2, N.sub.2) and the benefit curve **1202**. In other words, intersection point **1212** represents a shared point between the set of possible operating points defined by the annuity factor a.sub.2(r.sub.2, N.sub.2) (i.e., all the points along line **1204**) and the set of possible operating points defined by the asset size and the resulting benefit curve **1202** (i.e., all the points along benefit curve **1202**). Line **1206** does not intersect benefit curve **1202**. This indicates that the annuity factor a.sub.1(r.sub.1, N.sub.1) is too small to yield a solution for the asset size and resulting benefit curve **1202**.

(298) It should be noted that while the annuity factor a.sub.2(r.sub.2, N.sub.2) yields a feasible solution, this solution results in a negative net present value (i.e., −NPV.sub.2) at point **1210**. In graph **1200**, the value of the y-intercept is the negative net present value (i.e., −NPV). Lines that intercept the positive y-axis have a positive y-intercept and therefore a negative net present value. Conversely, lines that intercept the negative y-axis have a negative y-intercept and therefore a positive net present value.

(299) Referring now to FIG. **13**, another graph **1300** of initial investment cost C.sub.0 as a function of annual benefit C is shown, according to an exemplary embodiment. Graph **1300** is shown to include a benefit curve **1302** and a straight line **1304**. Line **1304** has the slope a(r, N) which can be determined based on specified values for the interest rate r and system life-cycle N. The annuity factor a(r, N) yields two possible solutions indicated by intersection points **1306** and **1308**. Both of these solutions have a positive net present value NPV indicated by negative value of the y-intercept **1310** (the negative of the net present value is negative, which makes the net present value positive). It is apparent from these examples that the asset

size solution is dependent upon the annuity factor a(r, N), which can be a function of the system life-cycle N and the target interest rate r and/or target payback period SPP.

(300) In some embodiments, the interest rate r and the system life-cycle N are provided as inputs to NPV optimizer **1022**. For example, the interest rate r and system life-cycle N can be specified by a user (e.g., received as inputs via a user interface), retrieved from memory, received from an external system or device, or otherwise provided as input parameters. NPV optimizer **1022** can be configured to calculate an annuity factor a(r, N) based on specified values for the interest rate r and system life-cycle N. The calculated annuity factor a(r, N) may define the slope of a straight line (e.g., line **1204**, line **1206**, line **1304**) which can be used to optimize the net present value of the system NPV.

(301) Referring now to FIG. **14**, another graph **1400** of initial investment cost C.sub.0 as a function of annual benefit C is shown, according to an exemplary embodiment. Graph **1400** is shown to include a benefit curve **1402** and a set of parallel lines **1404**, **1406**, **1408**, and **1410**. Each of the parallel lines **1404-1410** has the same annuity factor a(r, N) and therefore the same slope in graph **1400**. However, each of parallel lines **1404-1410** has a different y-intercept which corresponds to a different net present value.

(302) Line **1404** intersects benefit curve **1402** at two locations, both of which represent feasible asset size solutions. However, line **1404** has a positive y-intercept, which indicates a negative net present value for both of these solutions. Line **1406** also intersects benefit curve **1402** at two locations, both of which represent feasible asset size solutions. Line **1406** has a negative y-intercept, which indicates that both of these solutions have a positive net present value. Line **1408** intersects benefit curve **1402** at a single location (i.e., intersection point **1414**). This indicates a feasible asset size solution. Line **1408** has a negative y-intercept at point **1412**, which indicates a positive net present value for this solution. Line **1410** does not intersect benefit curve **1402** and therefore does not yield an asset size solution.

(303) NPV optimizer **1022** can be configured to find the asset size solution that results in a maximum NPV. From graph **1400**, it is apparent that the maximum NPV results from an asset size at which the slope of the benefit curve **1402** is equal to the annuity factor a(r, N). A line tangent to the benefit curve **1402** with a slope equal to the annuity factor a(r, N) (i.e., line **1408**) will intersect the benefit curve **1402** at a single point (i.e., point **1414**) and will have a y-intercept that defines the maximum NPV (i.e., point **1412**). Any line to the left of the tangent line **1408** (e.g., line **1404**, line **1406**) will yield a lower NPV. Any line to the right of the tangent line **1408** (e.g., line **1410**) will not yield a solution because such lines do not intersect the benefit curve. The intersection point **1414** of the tangent line **1408** and the benefit curve **1402** indicates the asset size which maximizes the NPV.

(304) In some embodiments, NPV optimizer **1022** determines the optimal asset size by finding the point at which the change in NPV (as a function of asset size) is equal to zero. For example, the NPV may be a function of both the annual benefit C and the purchase cost C.sub.0, as shown in the following equation:

(305) $NPV = a(r,N)C - C_0$

where both the annual benefit C and the initial purchase cost C.sub.0 are a function of asset size. NPV optimizer **1022** can iteratively adjust asset size to find the point at which the change in NPV relative to the change in asset size is zero or closest to zero

(306) $(e.g., \frac{NPV}{\text{size}} = 0)$.

This point is also the point at which the change in cost C.sub.0 relative the change in benefit C is equal to the annuity factor

(307) $(e.g., \frac{C_0}{C} = a(r,N))$.

Battery Sizing Example

(308) The following example illustrates an application of the asset sizing technique to an electrical energy storage system. The asset sizing technique can be used to determine the optimal size of a battery in the electrical energy storage system. A battery is a type of asset that has both a capacity size (i.e., an energy capacity) and a loading size (i.e., a power capacity). Accordingly, the optimal size of the battery may indicate both the optimal energy capacity and the optimal power capacity.

(309) Asset sizing module **916** can add two continuous decision variable terms to the original cost function J(x) to represent the energy capacity and the power capacity of the battery being sized. The continuous decision variable terms may have the form:

w.sub.EUC*r*.sub.EUC*C*.sub.eff and *w*.sub.PUC*r*.sub.PUC*P*.sub.eff

where r.sub.EUC and r.sub.PUC are the per unit costs of energy capacity (e.g., $/kWh) and power capacity (e.g., $/kW), C.sub.eff and P.sub.eff are the continuous decision variables representing energy capacity (e.g., kWh) and power capacity (e.g., kW) of the battery being sized, and w.sub.EUC and w.sub.PUC are the weight adjustments of energy capacity cost and power capacity cost over the optimization period (i.e., the factors used to scale the costs to the duration of the optimization period).

(310) Asset sizing module **916** can also add a binary decision variable term to the original cost function J(x) to represent the fixed cost associated with the battery being sized (i.e., the cost incurred regardless of energy capacity and power capacity). The binary decision variable term may have the form:

w.sub.bat*r*.sub.bat*v*

where r.sub.bat is the fixed cost of the battery being sized (e.g., $), v is a binary decision variable indicating whether the battery is purchased or not purchased, and w.sub.bat is the weight adjustment of the fixed cost over the optimization period (i.e., the factor used to scale the cost to the duration of the optimization period). The weight parameters w.sub.EUC, w.sub.PUC, and w.sub.bat may be functions of the duration of the optimization period and the annuity factor a(r, N). For example, the weight parameters may have the form:

(311) $w_{EUC} = w_{PUC} = w_{\text{bat}} = \frac{h}{8760 \text{ .Math. } a(r,N)}$

(312) The following equation is an example of the augmented cost function J.sub.a(x) after the continuous decision variable terms and binary decision variable term are added:

(313) $J_a(x) = -\text{ .Math. }_{i=k}^{k+h-1} r_{e_i} P_{\text{bat}_i} - \text{ .Math. }_{i=k}^{k+h-1} r_{FR_i} P_{FR_i} + \text{ .Math. }_{i=k}^{k+h-1} r_{s_i} s_i + w_d r_d d + w_{EUC} r_{EUC} C_{\text{eff}} + w_{PUC} r_{PUC} P_{\text{eff}} + w_{\text{bat}} r_{\text{bat}} v$

where P.sub.bat.sub.i is the allocated battery power (e.g., kW) for reducing energy cost and demand cost at the ith time step of the optimization period of duration h, r.sub.e.sub.i is cost per unit of electricity (e.g., $/kWh) at time step i, P.sub.FR.sub.i is the battery power committed to frequency response (FR) participation (e.g., kW) at the ith time step, r.sub.FR.sub.i is the FR incentive rate (e.g., $/kWh) at time step i, r.sub.s.sub.i is the cost associated with switching the power setpoint of the battery at time step i (e.g., $/kWh), s.sub.i is the switching auxiliary variable (e.g., kW), r.sub.d is the applicable demand charge rate (e.g., $/kW) corresponding to the demand charge period which overlaps with the optimization period, d is the electric demand (e.g., kW), w.sub.d is the weight adjustment of the demand charge (i.e., the factor used to scale the demand charge to the optimization period), and the remaining terms are the continuous decision variables and the binary decision variable terms, as previously described.

(314) Asset sizing module **916** can optimize the augmented cost function J.sub.a(x) subject to the following constraints:

$$P_{\text{bat}_i} + P_{FR_i} \le P_{\text{eff}}$$
$$-P_{\text{bat}_i} + P_{FR_i} \le P_{\text{eff}}$$
$$P_{\text{bat}_i} + P_{FR_i} \le e\text{Load}_i$$

(315) $$0 \begin{cases} C_a - \sum_{n=k}^{i} P_{\text{bat}_n} \le C_{\text{eff}} - C_{FR} P_{FR_i} \\ C_a - \sum_{n=k}^{i} P_{\text{bat}_n} \ge C_{FR} P_{FR_i} \end{cases} \quad \forall = k \ldots k+h-1$$

$$\begin{cases} C_a - \sum_{n=k}^{i} P_{\text{bat}_n} \le C_{\text{eff}} - C_{FR} P_{FR_{i+1}} \\ C_a - \sum_{n=k}^{i} P_{\text{bat}_n} \ge C_{FR} P_{FR_{i+1}} \end{cases} \quad \forall = k \ldots k+h-2$$

where eLoad.sub.i is the electric load at time step i (e.g., kWh), C.sub.a is the available battery capacity (e.g., kWh), and C.sub.FR is the FR reserve capacity (e.g., kWh/kW). The FR reserve capacity C.sub.FR may be the amount of energy in kWh to be reserved for FR per kW of power committed to FR.

(316) In some embodiments, the constraints imposed by asset sizing module **916** also include:

$$\begin{cases} d > P_{\text{bat}_i} + e\text{Load}_i \\ d > 0 \end{cases} \quad \forall = k \ldots k+h-1$$

(317) $$\begin{cases} s_i > P_{\text{bat}_i} - P_{\text{bat}_{i-1}} \\ s_i > P_{\text{bat}_{i-1}} - P_{\text{bat}_i} \end{cases} \quad \forall = k \ldots k+h-1$$

$$P_{\text{bat}_i} \le P_{\text{eff}}$$
$$-P_{\text{bat}_i} \le P_{\text{eff}}$$
$$C_{\text{eff}} - Mv \le 0$$
$$P_{\text{eff}} - C_{\text{rate}} C_{\text{eff}} \le 0$$

where M is a very large number (e.g., M=10.sup.10) and C.sub.rate is the maximum allowable power to energy ratio (e.g., P.sub.eff/C.sub.eff). This final constraint can be used to limit the power capacity and/or energy capacity of the battery such that P.sub.eff/C.sub.eff≤C.sub.rate.

Internal Rate of Return Optimization

(318) Referring again to FIG. **10**, financial metric optimizer **1020** is shown to include an internal rate of return (IRR) optimizer **1024**. IRR optimizer **1024** can be configured to find an asset size that optimizes the internal rate of return of the system in which the asset will be used. In some embodiments, IRR is defined as the interest rate r that causes the NPV to be zero. Accordingly, IRR can be substituted for interest rate r in the equation:

(319) $C_0 = a(r, N)C - NPV$

and NPV can be set to zero. This results in the following equation:

(320) $C_0 = a(\text{IRR}, N)C$

(321) This equation for C.sub.0 is that of a straight line passing through the origin and having a slope equal to the annuity factor a(IRR, N). The annuity factor a(IRR, N) is a function of IRR and may be inversely proportional to IRR (as shown in FIG. **11**). Accordingly, a decrease in IRR corresponds to an increase in the annuity factor a(IRR, N), and vice versa. However, an increase in the system life-cycle N or the simple payback period SPP may correspond to an increase in the annuity factor a(IRR, N).

(322) Referring now to FIG. **15**, another graph **1500** of initial investment cost C.sub.0 as a function of annual benefit C is shown, according to an exemplary embodiment. Graph **1500** is shown to include a benefit curve **1502** and several straight lines **1504**, **1506**, **1508**, and **1510**. Each of lines **1504-1510** has the form C.sub.0=a(IRR, N)C with a y-intercept of zero and a slope equal to a different annuity factor a(IRR, N). Line **1510** has the smallest value of the annuity factor a(IRR, N) and does not intersect benefit curve **1502**. This indicates that the annuity factor a(IRR, N) defining the slope of line **1510** does not yield an asset size solution. Lines **1504** and **1506** have larger values of the annuity factor a(IRR, N) and both intersect benefit curve **1502**. This indicates that the annuity factors a(IRR, N) defining the slopes of lines **1504** and **1506** yield feasible asset size solutions. However, none of the solutions corresponding to lines **1504** or **1506** correspond to the maximum IRR.

(323) Line **1508** is tangent to benefit curve **1502** and intersects benefit curve **1502** at a single point **1512**. Intersection point **1512** indicates the maximum value of IRR. Any lines with a slope greater than the slope of line **1508** (e.g., lines **1504** and **1506**) have a larger annuity factor a(IRR, N) and therefore a smaller value of IRR. Any lines with a slope less than the slope of line **1508** (e.g., line **1510**) have a smaller annuity factor a(IRR, N), but do not intersect benefit curve **1502** and therefore do not yield feasible asset size solutions. The annuity factor a(IRR, N) defining the slope of line **1508** is the minimum annuity factor (and therefore maximum IRR) which results in a feasible asset size solution.

(324) IRR optimizer **1024** can be configured to find the asset size solution that results in a maximum IRR. In some embodiments, IRR optimizer **1024** finds the optimal asset size by finding the point along benefit curve **1502** at which the slope of benefit curve **1502** is equal to the annuity factor a(IRR, N) (i.e., point **1512**). At point **1512**, the annuity factor a(IRR, N) has a slope equal to the tangent to benefit curve **1502**. This is the point beyond which any marginal increase in asset size (e.g., a size increase made when the allowable effective payback period is increased) would result in a lower rate of return. In other words, point **1512** corresponds to the smallest economically viable asset size.

(325) In some embodiments, IRR optimizer **1024** finds the asset size that optimizes IRR (or minimizes SPP) by incrementally increasing the target SPP or the target annuity factor a(IRR, N). For each target SPP value or target annuity factor value, IRR optimizer **1024** may solve the optimization problem over the duration of the optimization period (e.g., for an entire year). The solution to the optimization problem may indicate whether various assets are purchased or not purchased to achieve the optimal solution. IRR optimizer **1024** may identify the minimum target SPP value or target annuity factor that results in a solution in which an asset is purchased. The identified target SPP value or target annuity factor indicates the minimum viable payback period. The execution time required to implement the incremental increase approach may depend on the granularity with which the target SPP or annuity factor is increased. Lower granularity requires less execution time, but may select a minimum target SPP or annuity factor that exceeds the true minimum. Higher granularity may result in a solution that is closer to the true minimum, but may require more execution time.

(326) In some embodiments, IRR optimizer **1024** uses a divide and check approach to find the asset size that optimizes IRR. In this approach, IRR optimizer **1024** may identify the midpoint of the payback period to be tested and may perform the optimization using the identified midpoint as the target SPP value. If an asset is purchased in that optimization, IRR optimizer **1024** can determine that the minimum target SPP value is between zero and the midpoint. If the asset is not purchased in that optimization, IRR optimizer **1024** can determine that the minimum target SPP value is between the midpoint and the end of the payback period to be tested. The payback period to be tested can then be updated to the half of the payback period in which the minimum target SPP value is known to exist. This process can be repeated iteratively to converge on the minimum target SPP value.

(327) For example, the payback period to be tested may have a duration of 30 years. IRR optimizer **1024** can identify 15 years as the midpoint and can perform the asset size optimization using 15 years as the target SPP value. If an asset is purchased when 15 years is used as the target SPP value, IRR optimizer **1024** can determine that the minimum target SPP value is between zero and 15 years. If the asset is not purchased when 15 years is used as the target SPP value, IRR optimizer **1024** can determine that the minimum target SPP value is between 15 years and 30 years. The payback period to be tested can then be updated to either 0-15 years or 15-30 years, such that the new payback period to be tested includes the range in which the minimum target SPP value is known to exist. This process can be repeated iteratively until the payback period to be tested is reduced to a desired level of granularity.

(328) Given the maximum payback period to be tested and the desired level of granularity, the number of iterations required to converge on a solution is equal to:

(329) N_{runs} = ceiling{$\log_2(\frac{SPP_{\max}}{SPP})$}

where N.sub.runs is the number of iterations required, ΔSPP is the desired level of granularity (e.g., one day, one week, one year, etc.), and SPP.sub.max is the original duration of the payback period to be tested (e.g., 1 year, 10 years, 30 years, etc.). The result of this optimization is a value for the minimum target SPP value. IRR optimizer **1024** can use the minimum target SPP value to calculate the corresponding IRR. For example, IRR optimizer **1024** can set the annuity factor a(IRR, N) equal to the minimum target SPP and can find the value of IRR that achieves the specified value of a(IRR, N).

Asset Sizing Process

(330) Referring now to FIG. **16**, a flowchart of a process **1600** for determining optimal asset sizes is shown, according to an exemplary embodiment. Process **1600** can be performed by one or more components of frequency response optimization system **100**, photovoltaic energy system **300**, energy storage system **500**, planning system **700**, or any other type of energy storage system. In some embodiments, process **1600** is performed by energy storage controller **506** (as described with reference to FIGS. **5**A and **6**A) or controller **552** (as described with reference to FIGS. **5**B and **6**B). In some embodiments, process **1600** is performed by various components of high level optimizer **632** (e.g., asset sizing module **916**, cost function module **902**, etc.) as described with reference to FIGS. **9**-**10**.

(331) Process **1600** is shown to include generating a cost function defining a cost of operating HVAC equipment as a function of energy load setpoints for the HVAC equipment (step **1602**). In some embodiments, the cost function in step **1602** is the original cost function J(x). The cost function J(x) may include terms that accounts for energy purchase costs, demand charges, and peak load contribution (PLC) charges. In some embodiments, the cost function J(x) accounts for revenue from participating in IBDR programs such as frequency regulation (FR) or economic load demand response (ELDR).

(332) The HVAC equipment may include individual HVAC devices (e.g., chillers, boilers, fans, pumps, valves, etc.) or collections of HVAC devices (e.g., a chiller subplant, a heater subplant, a cooling tower subplant, etc.). In some embodiments, the HVAC equipment include energy storage such as thermal energy storage and/or electrical energy storage (e.g., batteries). Although HVAC equipment is used as an example in process **1600**, it should be understood that any type of equipment can be used. For example, the cost function generated in step **1602** may account for the cost associated with operating any type of equipment.

(333) Still referring to FIG. **16**, process **1600** is shown to include modifying the cost function to account for both an initial purchase cost of a new asset and a benefit of the new asset (step **1604**). Step **1604** may include augmenting the cost function J(x) with two new terms that correspond to the cost of purchasing the new asset, resulting in an augmented cost function J.sub.a(x). The additional terms are shown in the following equation:

J.sub.a(*x*)=*J*(*x*)+*c*.sub.f.sup.T*v*+*c*.sub.s.sup.T*s*.sub.a

where J(x) is the original cost function, x is the vector of decision variables of the optimization problem over the horizon, c.sub.f is a vector of fixed costs of buying any size of asset (e.g., one element for each potential asset purchase), v is a vector of binary decision variables that indicate whether the corresponding asset is purchased, c.sub.s is a vector of marginal costs per unit of asset size (e.g., cost per unit loading, cost per unit capacity), and s.sub.a is a vector of continuous decision variables corresponding to the asset size. Advantageously, the binary purchase decisions and asset size decisions are treated as decision variables which can be optimized along with the decision variables in the vector x. This allows high level optimizer **632** to perform a single optimization to determine optimal values for all of the decision variables in the augmented cost function J.sub.a(x).

(334) In some embodiments, step **1604** includes scaling the asset purchase costs c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a to the duration of the optimization period h. The cost of purchasing an asset is typically paid over an entire payback period SPP, whereas the operational cost is only over the optimization period h. In order to scale the asset purchase costs to the optimization period, step **1604** may include multiplying the terms c.sub.f.sup.Tv and c.sub.s.sup.Ts.sub.a by the ratio h/SPP as shown in the following equation:

(335) $J_a(x) = J(x) + \frac{h}{8760\ .\text{Math. SPP}}(c_f^T v + c_s^T s_a)$

where h is the duration of the optimization period in hours, SPP is the duration of the payback period in years, and 8760 is the number of hours in a year.

(336) The benefit of the new asset may include, for example, reduced energy costs, reduced demand charges, reduced PLC charges, and/or increased revenue from participating in IBDR programs such as FR or ELDR. The potential benefits and costs of an asset may vary based on the application of the asset and/or the system in which the asset will be used. For example, a system that participates in FR programs may realize the benefit of increased IBDR revenue, whereas a system that does not participate in any IBDR programs may not realize such a benefit. Some of the benefits and costs of an asset may be captured by the original cost function J(x). For example, the cost function J(x) may include terms corresponding to energy cost, multiple demand charges, PLC charges, and/or IBDR revenue, as previously described.

(337) Still referring to FIG. **16**, process **1600** is shown to include performing an optimization using the modified cost function to determine optimal values for decision variables in the modified cost function (step **1606**). The decision variables may include both the energy load setpoints and one or more asset size variables indicating the size of the new asset. In some embodiments, the asset size variables include a capacity size variable indicating a maximum capacity of the new asset and a loading size variable indicating a maximum loading of the new asset.

(338) In some embodiments, step **1606** includes optimizing the cost defined by the modified cost function. In other embodiments, step **1606** includes optimizing a financial metric comprising at least one of net present value, internal rate of return, or simple payback period. Step **1606** may include using mixed integer linear programming to optimize the modified cost function and/or the financial metric.

(339) In some embodiments, step **1606** includes generating a benefit curve defining a relationship between the initial purchase cost of the new asset and the benefit of the new asset. In some embodiments, step **1606** includes defining a net present value of the system as a function of the initial purchase cost of the new asset and the benefit of the new asset. Both the initial purchase cost and the benefit of the new asset may depend on the asset size variables. Step **1606** may include calculating the net present value of the system for a plurality of points along the benefit curve, optimizing the net present value by finding an optimal point along the benefit curve that maximizes the net present value, and determining a value of the asset size variable that corresponds to the optimal point along the benefit curve.

(340) In some embodiments, step **1606** includes incrementally increasing a target variable including at least one of a simple payback period or an annuity factor. Step **1606** may include optimizing the modified objective function for each value of the target variable and determining whether the new asset is purchased based on the optimal values of the asset size variables. Step **1606** may include optimizing an internal rate of return by finding a minimum value of the target variable that results in the new asset being purchased.

(341) In some embodiments, step **1606** includes defining an internal rate of return as a function of the initial purchase cost of the new asset and the benefit of the new asset. Both the initial purchase cost and the benefit of the new asset may depend on the asset size variables. Step **1606** may include calculating the internal rate of return for a plurality of points along the benefit curve, optimizing the internal rate of return by finding an optimal point

along the benefit curve that maximizes the internal rate of return, and determining a value of the asset size variable that corresponds to the optimal point along the benefit curve.
(342) In some embodiments, step **1606** includes executing a stochastic optimization process to determine optimal values for decision variables in the modified cost function. For example, projected values of non-predetermined terms may be obtained for a plurality of scenarios, i.e., for many possible situations that may occur during an optimization period. For example, projected building loads, utility rates, IBDR/PBDR requests or schedules, and/or some other non-pre-determined values may be obtained for a plurality of scenarios. The cost function can then be optimized over the plurality of scenarios, for example to select an asset size that optimizes the internal rate of return or other metric over the plurality of scenarios. In some cases, the stochastic optimization process includes performing a first optimization to determine an asset size target that minimizes a risk attribute of the cost function over the plurality of scenarios and performing a second optimization subject to a constraint defined by the asset size target over the plurality of scenarios to determine values for energy load setpoints, asset size variables, and participation in an incentive program. Optimization and asset size determination may thereby be configured to account for stochastic variation in building loads, utility rates, IBDR/PBDR requests or schedules, and/or other terms over time. The present disclosure contemplates various adaptations, implementations, modifications, etc. of the systems and methods described in U.S. patent application Ser. No. 16/115,290, filed Aug. 28, 2018 for uses with the asset sizing systems and methods described herein. The entire disclosure of U.S. patent application Ser. No. 16/115,290 is incorporated by reference herein.
(343) Still referring to FIG. **16**, process **1600** is shown to include using the optimal energy load setpoints to operate the HVAC equipment (step **1608**). In some embodiments, step **1608** is performed when process **1600** is part of an online optimization routine. For example, step **1608** can be performed by any of the controllers described with reference to FIGS. **1-6** to provide setpoints to equipment. However, step **1608** may be omitted if process **1600** is performed in an offline environment. For example step **1608** may be omitted if process **1600** is performed by planning tool **702**.
(344) In some embodiments, in addition to or instead of operating the HVAC equipment at step **1608**, the process **1600** includes initiating a process to acquire and install the new asset having an asset size based on the values of the asset size variables resulting from the optimization of the modified cost function. For example, in some embodiments the asset sizing module **916** generates a purchase order or other request to obtain (e.g., purchase, lease, ship, obtain, install) a recommended device of storage equipment. In some cases, a new device may be automatically ordered and delivered in response to the optimization of step **1616**. In some embodiments, the asset sizing module **916** automatically notifies a technician, service representative, etc. of the optimal asset size and/or automatically schedules an appointment for ordering and/or installation of a new device. The various subplants and building equipment may be controlled to facilitate installation of the new asset, for example by shifting loads or stored resources away from devices that may need to be deactivated during an installation time.
(345) In some embodiments, the process **1600** includes installing a new asset having the optimal asset size as determined at step **1606**, configuring the new asset to communicate with and operate as controlled by the energy storage controller **506** and/or the controller **522**, re-establishing the plant model to account for the new asset, and controlling the new asset and pre-existing assets (e.g., the various generator subplants **520** and storage subplants **530**) in accordance with an output of one or more of the optimization processes described herein. Process **1600** may thereby result in optimal operation of an updated, higher-efficiency, cost-effective plant.
Configuration of Exemplary Embodiments
(346) The construction and arrangement of the systems and methods as shown in the various exemplary embodiments are illustrative only. Although only a few embodiments have been described in detail in this disclosure, many modifications are possible (e.g., variations in sizes, dimensions, structures, shapes and proportions of the various elements, values of parameters, mounting arrangements, use of materials, colors, orientations, etc.). For example, the position of elements can be reversed or otherwise varied and the nature or number of discrete elements or positions can be altered or varied. Accordingly, all such modifications are intended to be included within the scope of the present disclosure. The order or sequence of any process or method steps can be varied or re-sequenced according to alternative embodiments. Other substitutions, modifications, changes, and omissions can be made in the design, operating conditions and arrangement of the exemplary embodiments without departing from the scope of the present disclosure.
(347) The present disclosure contemplates methods, systems and program products on any machine-readable media for accomplishing various operations. The embodiments of the present disclosure can be implemented using existing computer processors, or by a special purpose computer processor for an appropriate system, incorporated for this or another purpose, or by a hardwired system. Embodiments within the scope of the present disclosure include program products comprising machine-readable media for carrying or having machine-executable instructions or data structures stored thereon. Such machine-readable media can be any available media that can be accessed by a general purpose or special purpose computer or other machine with a processor. By way of example, such machine-readable media can comprise RAM, ROM, EPROM, EEPROM, CD-ROM or other optical disk storage, magnetic disk storage or other magnetic storage devices, or any other medium which can be used to carry or store desired program code in the form of machine-executable instructions or data structures and which can be accessed by a general purpose or special purpose computer or other machine with a processor. Combinations of the above are also included within the scope of machine-readable media. Machine-executable instructions include, for example, instructions and data which cause a general purpose computer, special purpose computer, or special purpose processing machines to perform a certain function or group of functions.
(348) Although the figures show a specific order of method steps, the order of the steps may differ from what is depicted. Also two or more steps can be performed concurrently or with partial concurrence. Such variation will depend on the software and hardware systems chosen and on designer choice. All such variations are within the scope of the disclosure. Likewise, software implementations could be accomplished with standard programming techniques with rule based logic and other logic to accomplish the various connection steps, processing steps, comparison steps and decision steps.

Claims

1. An energy optimization system for one or more buildings, the system comprising: HVAC equipment configured to satisfy a building energy load; and one or more memory devices having instructions stored thereon that, when executed by one or more processors, cause the one or more processors to: obtain a cost function defining a total cost over an optimization period as a function of: an initial purchase cost of a new asset to be added to the HVAC equipment, wherein the initial purchase cost of the new asset comprises a function of one or more asset size variables defining a size of the new asset, wherein the new asset comprises at least one of a heat recovery chiller, a solar energy system, a hydroelectric system, or an energy storage system; and a cost of operating the HVAC equipment and the new asset based on one or more energy load setpoints for the HVAC equipment and the new asset; perform an optimization using the cost function to determine values for decision variables in the cost function including the one or more energy load setpoints for the HVAC equipment and the new asset and the one or more asset size variables, wherein the one or more energy load setpoints for the HVAC equipment and the new asset depend on the one or more asset size variables; perform an action that causes the new asset having the size defined by the one or more asset size variables to be installed; and operate the HVAC equipment and the new asset based on the determined values of one or more energy load setpoints for the HVAC equipment and the new asset.
2. The energy optimization system of claim 1, wherein the optimization is performed subject to a constraint related to a use of a resource supplied to the HVAC equipment by one or more utilities.
3. The energy optimization system of claim 2, wherein the constraint comprises a term comprising a coefficient multiplied by an amount of the resource supplied by the one or more utilities.
4. The energy optimization system of claim 1, wherein the asset size variables comprise at least one of: a capacity size variable indicating a

maximum capacity of the new asset; or a loading size variable indicating a maximum loading of the new asset.
5. The energy optimization system of claim 1, wherein the optimization is performed by optimizing a financial metric comprising at least one of net present value, internal rate of return, or simple payback period.
6. The energy optimization system of claim 1, wherein the optimization is performed by: receiving a target value for at least one of an interest rate or an asset life-cycle; calculating a target value for a simple payback period based on the target value for at least one of the interest rate or the asset life-cycle; scaling one or more asset size cost terms in the cost function to a duration of the optimization period; performing the optimization over the optimization period to determine current values of the asset size variables; and repeating the optimization to determine values of the asset size variables and carrying over the values of the asset size variables, wherein the values of the asset size variables correspond to an optimal net present value.
7. The energy optimization system of claim 1, wherein the optimization is performed by: varying a target variable comprising at least one of a simple payback period or an annuity factor; for each value of the target variable, scaling one or more asset size cost terms in the cost function to a duration of the optimization period; for each value of the target variable, optimizing the cost function and determining whether the new asset is purchased based on the values of the asset size variables; and optimizing an internal rate of return by finding a minimum value of the target variable that results in the new asset being purchased.
8. The energy optimization system of claim 1, wherein the instructions cause the one or more processors to generate a benefit curve defining a relationship between the initial purchase cost of the new asset and a benefit of the new asset, wherein the benefit of the new asset is based on an effect of the new asset on the total cost.
9. The energy optimization system of claim 8, wherein the optimization is performed by: defining a net present value of the system as a function of the initial purchase cost of the new asset and the benefit of the new asset, wherein both the initial purchase cost and the benefit of the new asset depend on the asset size variables; calculating the net present value of the system for a plurality of points along the benefit curve; optimizing the net present value by finding an optimal point along the benefit curve that maximizes the net present value; and determining a value of the asset size variable that corresponds to the optimal point along the benefit curve.
10. The energy optimization system of claim 8, wherein the optimization is performed by: defining an internal rate of return as a function of the initial purchase cost of the new asset and the benefit of the new asset, wherein both the initial purchase cost and the benefit of the new asset depend on the asset size variables; calculating the internal rate of return for a plurality of points along the benefit curve; optimizing the internal rate of return by finding an optimal point along the benefit curve that maximizes the internal rate of return; and determining a value of the asset size variable that corresponds to the optimal point along the benefit curve.
11. A method for optimizing equipment that serve one or more buildings, the method comprising: obtaining a cost function defining a total cost over an optimization period as a function of: an initial purchase cost of a new asset to be added to the equipment, wherein the initial purchase cost of the new asset depends at least partially on one or more asset size variables defining a size of the new asset, wherein a first set of decision variables in the cost function comprise the one or more asset size variables; and an effect of the new asset on a cost of operating the equipment, wherein the cost of operating the equipment depends at least partially on one or more energy load setpoints for the equipment and the new asset to be added to the equipment, wherein the one or more energy load setpoints are a second set of decision variables in the cost function, wherein the one or more energy load setpoints depend on the one or more asset size variables; performing an optimization using the cost function to determine optimal values for the first set of decision variables and the second set of decision variables including the one or more energy load setpoints and the one or more asset size variables, performing an action that causes the new asset having the size defined by the one or more asset size variables to be installed; and operating the equipment and the new asset based on the determined optimal values for the one or more energy load setpoints for the equipment and the new asset.
12. The method of claim 11, wherein the optimization is performed subject to a constraint related to a use of a resource supplied to the equipment by one or more utilities.
13. The method of claim 12, wherein the constraint comprises a term comprising a coefficient multiplied by an amount of the resource supplied by the one or more utilities.
14. The method of claim 11, wherein the asset size variables comprise at least one of: a capacity size variable indicating a maximum capacity of the new asset; or a loading size variable indicating a maximum loading of the new asset.
15. The method of claim 11, wherein performing the optimization comprises optimizing a financial metric comprising at least one of net present value, internal rate of return, or simple payback period.
16. The method of claim 11, further comprising generating a benefit curve defining a relationship between the initial purchase cost of the new asset and a benefit of the new asset, wherein the benefit of the new asset is based on the effect of the new asset on the total cost of operating the equipment.
17. The method of claim 16, wherein performing the optimization comprises: defining a net present value of the system as a function of the initial purchase cost of the new asset and the benefit of the new asset, wherein both the initial purchase cost and the benefit of the new asset depend on the asset size variables; calculating the net present value of the system for a plurality of points along the benefit curve; optimizing the net present value by finding an optimal point along the benefit curve that maximizes the net present value; and determining a value of the asset size variable that corresponds to the optimal point along the benefit curve.
18. The method of claim 16, wherein performing the optimization comprises: defining an internal rate of return as a function of the initial purchase cost of the new asset and the benefit of the new asset, wherein both the initial purchase cost and the benefit of the new asset depend on the asset size variables; calculating the internal rate of return for a plurality of points along the benefit curve; optimizing the internal rate of return by finding an optimal point along the benefit curve that maximizes the internal rate of return; and determining a value of the asset size variable that corresponds to the optimal point along the benefit curve.
19. The method of claim 11, wherein performing the optimization comprises: varying a target variable comprising at least one of a simple payback period or an annuity factor; for each value of the target variable, optimizing the cost function and determining whether the new asset is purchased based on the optimal values of the asset size variables; and optimizing an internal rate of return by finding a minimum value of the target variable that results in the new asset being purchased.
20. An energy optimization system, the system comprising: one or more memory devices having instructions stored thereon that, when executed by one or more processors, cause the one or more processors to: obtain a cost function comprising: a cost of operating equipment over an optimization period as a function of one or more asset size variables and one or more energy load setpoints for the equipment and a new asset to be added to the equipment, wherein the one or more asset size variables comprise at least one of a capacity size variable related to a maximum capacity of the new asset to be added to the equipment or a loading size variable related to a maximum loading of the new asset; and an initial purchase cost of the new asset, wherein the initial purchase cost of the new asset is a function of the one or more asset size variables defining a size of the new asset; perform an optimization using the cost function to determine values for the one or more asset size variables and the one or more energy load setpoints for the equipment and the new asset; perform an action that causes the new asset having the size defined by the one or more asset size variables to be installed, wherein the new asset comprises at least one of a heat recovery chiller, a solar energy system, a hydroelectric system, or an energy storage system, wherein the optimization is performed subject to a constraint related to a use of a resource supplied to the energy optimization system by one or more utilities; and operate the equipment and the new asset based on the determined values for the one or more energy load setpoints for the equipment and the new asset.