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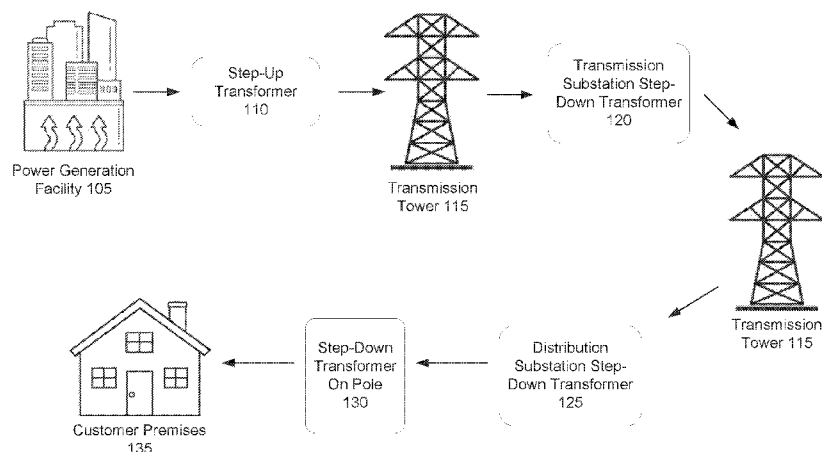
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(54) Title: AUTOMATED MODEL VALIDATION SYSTEM FOR ELECTRICAL GRID

FIG. 1



(57) Abstract: Provided is a system and method for automated power system model validation. The system can detect a disturbance on an electrical grid, identify sensors that are near the disturbance, correlate the sensors to a subsystem on the grid, and perform a power system model validation for the subsystem. In one example, the method may include in response to an event on an electrical grid, identifying a PMU of the electrical grid based on a geographical location of the event, mapping the identified PMU to a power generation system on the electrical grid based on a tag of the identified PMU and a tag of the power generation system, retrieving a power system model of the power generation system, and triggering a validation determination of the power system model of the power generation system based on event data sensed by the identified PMU.

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AUTOMATED MODEL VALIDATION SYSTEM FOR ELECTRICAL GRID

BACKGROUND

[0001] Grid planning and operating decisions are often based on the results of power system simulations. These simulations rely on power system models to predict system performance during anticipated disturbance events. Both technical and commercial segments of the industry must be confident that the dynamic simulation models, including all of their data, are accurate and up-to-date. Optimistic models can result in grid under-investment or unsafe operating conditions and ultimately widespread power outages. On the other hand, pessimistic models and assumptions can result in overly conservative grid operation and under-utilization of network capacity. Pessimistic models can also lead to unnecessary capital investment, thereby increasing the cost of electric power. Therefore, realistic models are needed for ensuring reliable and economic power system operation.

[0002] Power system models are the foundation of virtually all power system studies. Calculation of operating limits, planning for assessment of new generation and load growth, performance assessments of system integrity protection schemes (SIPS), and the like, depend on an approximate mathematical representation of the transmission, generation, and load of an electrical grid. Disturbances in the electrical grid provide an excellent opportunity to validate a power system model. In order to validate the power system model, disturbance data must be collected from appropriate systems on the grid, network topology information of the electrical grid must be collected, dynamic models at the time of the event must be collected, and sensor data must somehow be correlated to power system data on the grid. However, these processes are typically performed by an operator (human) and often require significant amounts of time and cost. As a result, validation of power system models is not regularly performed.

[0003] There are always evolving changes in the characteristics of the power system over time, particularly with respect to loads. Unforeseen interactions can also occur when new control strategies are implemented through the addition of novel devices and technologies. Therefore, power system models should be checked and validated on a regular basis to ensure that trends in the power system which can affect reliability are captured. Such validation can prevent blackouts as well as exorbitant costs. Accordingly, a system is

needed which can improve the speed at which power system model validation occurs while moving away from reliance on human interaction.

SUMMARY

[0004] The example embodiments describe a system which improves upon the prior art by auto-detecting a disturbance on the electrical grid, identifying phasor measurement units (PMUs) associated with the disturbance, and triggering an automated power system model validation based on disturbance data captured by the identified PMUs. In some embodiments, the system may identify one or more PMUs that have relevant data associated with the disturbance based on a disturbance impact factor generated for the PMU. The system may also automatically correlate the identified PMUs to one or more power generation systems on the electrical grid (*e.g.*, substations, transmission lines, etc.) that are associated with the disturbance. The correlation may involve an automated tag-mapping process between PMU name tags and energy management system (EMS) name tags. Furthermore, the system may automatically validate a power system model of the power generation systems based on the PMU data that is captured of the event.

[0005] In an aspect of an example embodiment, a computing system may include a storage configured to store information about an event on an electrical grid, and a processor configured to, in response to the event on the electrical grid being detected, identify a PMU of the electrical grid based on a geographical location of the event, map the identified PMU to a power generation system on the electrical grid based on a tag of the identified PMU and a tag of the power generation system, and retrieve a power system model of the power generation system from a repository. Furthermore, the processor may trigger a validation determination of the power system model based on event data sensed by the identified PMU.

[0006] In an aspect of another example embodiment, a method may include, in response to an event on an electrical grid, identifying a PMU of the electrical grid based on a geographical location of the event, mapping the identified PMU to a power generation system on the electrical grid based on a tag of the identified PMU and a tag of the power generation system, retrieving a power system model of the power generation system, and triggering a validation determination of the power system model of the power generation system based on event data sensed by the identified PMU.

[0007] Other features and aspects may be apparent from the following detailed description taken in conjunction with the drawings and the claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] Features and advantages of the example embodiments, and the manner in which the same are accomplished, will become more readily apparent with reference to the following detailed description taken in conjunction with the accompanying drawings.

[0009] FIG. 1 is a diagram illustrating a system for delivering electricity to a customer in accordance with an example embodiment.

[0010] FIG. 2 is a diagram illustrating a network topology of an electrical grid in accordance with an example embodiment.

[0011] FIG. 3 is a diagram illustrating a system including an enhanced disturbance management (EDM) module in accordance with an example embodiment.

[0012] FIG. 4 is a diagram illustrating a framework for validating power system models in accordance with an example embodiment.

[0013] FIG. 5 is a diagram illustrating an automated model validation system in accordance with an example embodiment.

[0014] FIG. 6 is a method for triggering validation of a power system model in accordance with an example embodiment.

[0015] FIG. 7 is a diagram illustrating a computing system for use in the methods and processes described herein.

[0016] FIG. 8A is a diagram illustrating a process of tag-mapping in accordance with an example embodiment.

[0017] FIG. 8B is a diagram illustrating a human machine interface for automatic model validation in accordance with an example embodiment.

[0018] FIG. 9 is a diagram illustrating a human machine interface displaying calibration information in accordance with an example embodiment.

[0019] FIG. 10 is a diagram illustrating table data stored in an AMV expert system in accordance with an example embodiment.

[0020] FIG. 11 is a diagram illustrating a system that includes an automatic model validation system in accordance with an example embodiment.

[0021] Throughout the drawings and the detailed description, unless otherwise described, the same drawing reference numerals will be understood to refer to the same elements, features, and structures. The relative size and depiction of these elements may be exaggerated or adjusted for clarity, illustration, and/or convenience.

DETAILED DESCRIPTION

[0022] In the following description, specific details are set forth in order to provide a thorough understanding of the various example embodiments. It should be appreciated that various modifications to the embodiments will be readily apparent to those skilled in the art, and the generic principles defined herein may be applied to other embodiments and applications without departing from the spirit and scope of the disclosure. Moreover, in the following description, numerous details are set forth for the purpose of explanation. However, one of ordinary skill in the art should understand that embodiments may be practiced without the use of these specific details. In other instances, well-known structures and processes are not shown or described in order not to obscure the description with unnecessary detail. Thus, the present disclosure is not intended to be limited to the embodiments shown, but is to be accorded the widest scope consistent with the principles and features disclosed herein.

[0023] Existing Model validation data preparation is a manual process, which is time consuming, costly and prone to human error. The example embodiments provide a framework for an automated model validation system which can detect a disturbance event and identify affected PMU locations based on disturbance information. For example, the system may select PMUs that have adequate responses to the event. The system may correlate (e.g., map) the selected PMUs to generator systems on the electrical grid using an automated tag-mapping operation which resolves differences between PMU names and EMS names for power generating systems on the grid. Based on the mapping, the system can carve out the subsystem(s) on the electrical grid that are affected by the disturbance and which should be validated.

[0024] Furthermore, the framework may include a data collection system which establishes a communication channel between existing EMS, PMU, and Enhanced

Disturbance Monitoring (EDM) systems and automatically retrieves power system models of the subsystems affected by the disturbance. Furthermore, an automated model validation (AMV) system may validate the power system models based on the PMU data. When the AMV system determines a power system model is not valid, the AMV system may notify an operator thereof. As another option, the system may determine updated parameters for the invalid model which improve the model, and provide the results to the operator via a user interface, etc.

[0025] The behavior of power plants and electrical grids may change over time and should be checked and updated to assure that they remain accurate. Engineers use the processes of validation and calibration to make sure that a power system model can accurately predict the behavior of the modeled object (*e.g.*, transmission system, generating unit, load, etc.) Validation assures that the model accurately represents the operation of the real system including model structure, correct assumptions, and that the output matches actual events. Once the model is validated, a calibration process may be used to make minor adjustments to the model and its parameters so that the model continues to provide accurate outputs. High-speed, time-synchronized data, collected using PMUs may facilitate model validation of the dynamic response to grid events. Grid operators may use, for example, PMU data recorded during normal plant operations and grid events to validate grid and power plant models quickly and at lower cost.

[0026] The transmission operators, Regional reliability coordinators, Independent System Operators, and the like such as MISO, ISO-New England, PG&E, etc., can use this calibrated generator or power system model for power system stability study based on N-k contingencies, in every 5 to 10 minutes. If there is a stability issue (transient stability) for some specific contingency, the power flow may be redirected to relieve the stress-limiting factors. For example, the output of some power generators will be adjusted to redirect the power flow. Alternatively, adding more capacity (more power lines) to the existing system can be used to increase the transmission capacity.

[0027] With a model that accurately reflects oscillations and their causes, the grid operator can also diagnose the causes of operating events, such as wind-driven oscillations, and identify appropriate corrective measures before those oscillations spread to harm other assets or cause a loss of load.

[0028] As used herein, devices, including those associated with the system and any other device described herein, may exchange information via any communication network which may be one or more of a Local Area Network ("LAN"), a Metropolitan Area Network ("MAN"), a Wide Area Network ("WAN"), a proprietary network, a Public Switched Telephone Network ("PSTN"), a Wireless Application Protocol ("WAP") network, a Bluetooth network, a wireless LAN network, and/or an Internet Protocol ("IP") network such as the Internet, an intranet, or an extranet. Note that any devices described herein may communicate via one or more such communication networks.

[0029] FIG. 1 is a diagram illustrating example embodiments of a power delivery process 100 showing components that can facilitate the generation of power and the process of delivering power (e.g., delivering energy, electricity) to customer premises. Electric power can be generated at a power generation facility, and then carried by transmission power lines to substations having transformers. A local distribution system of smaller, lower-voltage transmission lines and substations carry power to the customer premises. In the example of FIG. 1, a power generation facility 105 generates electricity to meet the power demands of customers. A variety of facilities can generate electricity. For example, power generation facilities 105 can include power plants that burn coal, oil, or natural gas. Power generation facilities 105 can also comprise nuclear power plants, renewable sources of energy such as hydroelectric dams, wind turbines, and solar panels, and the like. The location of these electricity generators, and their distance from end users, can vary widely.

[0030] The electricity that is generated by the power generation facility 105 may be stepped up or stepped down by transformers (e.g., transformer 110) which may be located at power plant substations adjacent to (and connected via power lines to) the power plant. In this example, the transformer 110 is a step-up transformer that will "step up" the voltage of the electricity. When power travels through power lines (e.g., metallic wires that conduct electricity), some of that power is wasted in the form of heat. The power loss is proportional to the amount of current being carried. Power companies keep the current low and compensate by stepping up the voltage. After the voltage is stepped up, the electricity is typically carried over long distances by high voltage power transmission lines, typically supported and elevated by transmission towers (e.g., transmission towers 115) that can be of various dimensions, materials, and heights.

[0031] In some embodiments, the voltage may be gradually reduced by step-down transformers as the electricity approaches customer premises. Transmission substations contain step-down transformers (e.g., transmission substation step-down transformer 120) that reduce the voltage of the electricity. The electricity can then be distributed on lower-voltage power lines. A typical transmission substation can serve tens of thousands of customers. The electricity leaving transmission substations can travel through power lines to distribution substations. Distribution substations contain step-down transformers (e.g., distribution substation step-down transformer 125) that further reduce the voltage of electricity and distribute the power to cities and towns through main power lines, which can serve hundreds of customers. Distribution lines carry lower voltage power to clusters of homes and businesses, and are typically supported by wooden poles. Of note, power lines can also be buried under the ground. Of note, substations can contain a variety of other equipment, including switches, breakers, regulators, batteries, etc.

[0032] The voltage from a branch line can further be reduced by transformers that are mounted on poles (e.g., step-down transformer on pole 130) that connect customer premises (e.g., customer premises 135) through a service drop power line. Customer premises 135 can be of any type and variety. Customer premises can be a residential customer premises, such as residential houses. Customer premises can be an industrial customer premises, such as factories. Customer premises can be commercial customer premises, such as an office building. If a particular customer premises has a heavier load (e.g., has a higher demand for power), then a larger transformer, instead of a pole transformer, might service that particular customer premises.

[0033] FIG. 2 depicts an illustration of a power grid system 200 (e.g., an electrical grid) comprising multitudes of nodes 201-210. In this example, a node may represent a power generation facility, transmission substation, a distribution substation, and the like, and is intended to convey that such facilities and substations can be interconnected. In the examples herein, a node may be referred to as a “power system node.” The power grid system 200 can follow a structural topology, influenced by factors such as budget, system reliability, load demand (demand for power), land, and geology. The structural topology in many cities and towns, for example many of those in North America, tends to follow a classic radial topology. This is a tree-shape network wherein power from larger voltage lines and substations radiates out into progressively lower voltage lines and substations until the customer premises are reached.

[0034] A substation receives its power from a power generation facility, and the power may be stepped down with a transformer and sent through lines that spread out in all directions across the countryside. These feeders carry three-phase power and tend to follow major streets near the substation. As the distance from the substation grows, the fanout continues as smaller laterals spread out to cover areas missed by the feeders. This tree-like structure grows outward from the substation, but a single power failure can render inoperable entire branches of the tree. For reliability reasons, there are often unused backup connections from one substation to a nearby substation. This backup connection can be enabled in case of an emergency, such that a part of a substation's service area can be fed by another substation in case of any power failure events. Redundancy allows line failures to occur and power to be rerouted while workmen restore to service damaged or deactivated components. Neighboring power utilities also typically link their grids, thereby assisting one another to maintain a balance between power generation supply and loads (e.g., customer demand). Other topologies can be mesh topologies, looped systems (mostly found in Europe) and ring networks.

[0035] The result can be an interconnected power grid system 200 that can form complex networks of power plants and transformers connected by hundreds of thousands of miles of high-voltage transmission lines. While these interconnections can be useful in situations, the danger or risk can comprise the possibility that a shutdown in one sector could rapidly spread to other sectors, leading to massive power failures in a wide area.

[0036] In the example of FIG. 2, disposed within the power grid system 200 are measurement devices 220A-220E. Throughout a power network, a variety of sensors, monitoring devices and measurement devices (collectively referred to herein as "measurement devices") can be located at one or more nodes (e.g., nodes 201-210), in between nodes on lines, and the like, and can be used to provide monitoring data related to power flow measurements, or monitor the condition of one or more aspects of a power grid system. The measurement devices 220A-220E may be deployed within, or adjacent to, power transmission components (e.g., generating units, transformers, circuit breakers), including at substations. In some examples, the measurement devices 220A-220E can also be deployed along distribution lines.

[0037] The measurement devices 220A-220E may include sensors that measure a range of parameters such as magnitude and phase angle of voltage, current, harmonic

distortion, real and reactive power, power factor, and fault current. Examples of some sensors include, but are not limited to, voltage and current sensors, PMUs, transformer-Metal Insulated Semiconducting (MIS) gas in oil sensors, circuit breaker sulfur hexafluoride density sensors, conductor temperature and current sensors that record overhead transmission conductor temperatures and current magnitudes, overhead insulator leakage current sensors, Transmission Line Surge Arrester (TLSA) sensors, and the like.

[0038] In the example of FIG. 2, the power grid system 200 may include the measurement devices 220A-220E located in various parts (e.g., such as nodes) throughout the grid. The measurement devices 220A-220E can be coupled via a network of transmission lines, as well as through wireless and wired communications mediums (e.g., cellular, ethernet, etc.). For example, a measurement device 220E can be coupled via a transmission line 222 from a network of transmission lines associated with the nodes 201-210. Furthermore, a subset of the measurement devices can be associated with a sector of the power grid system 200.

[0039] In example embodiments, the reliability of the power grid system 200 can be facilitated through the use and analysis of the data received from measurement devices 220A-220E and monitoring of system conditions that are then communicated to a central control center, where a combination of automated actions and human decision assist in striving to ensure that the power grid system 200 is stable and balanced. For example, a measurement device may include a phasor measurement unit (PMU) which can capture data of a disturbance event. PMUs typically have a naming convention based on PMU information which is defined by a regional transmission authority. Meanwhile, power system nodes 201-210 have a naming convention based on utility companies. As a result, the measurement devices 220A-220E may have names that are not identical to or correlated with the names of the power system nodes 201-210. As further described herein, the system can perform automated tag mapping to correlate the measurement devices 220A-220E with corresponding power system nodes 201-210.

[0040] Among other operations, described herein is an Enhanced Disturbance Management (EDM) component (e.g., module) that is operable to read (e.g., obtain) monitoring data, for example, Supervisory Control and Data Acquisition (SCADA) system data, PMU-based data, topology data, and the like, based on power flow measurements associated with measurement devices (e.g., PMUs, current sensors, voltage sensors, etc.)

connected to an electrical power system (e.g., electric power system, electrical energy system, electric energy system, power grid system, etc.), wherein the monitoring data can comprise alarm data indicative of an electrical disturbance within the electrical power system, and topology data indicative of a topology of the electrical power system. The EDM component can be operable to correlate the alarm data, which can relate to, for example, an angle disturbance alarm, or, for example, a frequency disturbance alarm, with a change in the topology data.

[0041] FIG. 3 illustrates a system 300 including an EDM module 316 in accordance with an example embodiment. In this example, the EDM module 316 can determine a characterization (e.g., classification, causation) of the electrical disturbance in the power grid system based on the correlating of the alarm data with the topology data, determining a coherency level representative of the degree of correlation between the alarm data and the topology data, determining a Disturbance Impact Factor (DIF) indicative of an impact of the electrical disturbance on a location in the power grid system, and identify one or more sensors (PMUs) that have captured data of the disturbance. The EDM module 316 can further auto-map PMUs to one or more power system nodes on the grid, retrieve power model information of the power system nodes, and validate the retrieved power model based on the PMU information of the disturbance. In some embodiments, the EDM module 316 can also store and display disturbance history, event history, and a variety of other statistical information related to disturbances and events, including on a graphical user interface, or in a generated report.

[0042] Measurement device 220 in FIG. 3 can obtain, monitor or facilitate the determination of electrical characteristics associated with the power grid system (e.g., the electrical power system), which can comprise, for example, power flows, voltage, current, harmonic distortion, frequency, real and reactive power, power factor, fault current, and phase angles. Measurement device 220 can also be associated with a protection relay, a Global Positioning System (GPS), a Phasor Data Concentrator (PDC), communication capabilities, or other functionalities.

[0043] Measurement devices 220 can provide real-time measurements of electrical characteristics or electrical parameters associated with the power grid system (e.g., the electrical power system). The measurement device 220 can, for example, repeatedly obtain measurements from the power grid system (e.g., the electrical power system) that can be used

by the EDM module 316. The data generated or obtained by the measurement device 220 can be coded data (e.g., encoded data) associated with the power grid system that can input (or be fed into) a traditional SCADA/EMS system. The measurement device 220 can also be a PMU that repeatedly obtains subs-second measurements (e.g., 30 times per second). Here, the PMU data can be fed into, or input into, applications (e.g., Wide Area Monitoring System (WAMS) and WAMS-related applications) that can utilize the more dynamic PMU data (explained further below).

[0044] In the example of FIG. 3, the measurement device 220 includes a voltage sensor 302 and a current sensor 304 that feed data typically via other components, to, for example, a Supervisory Control and Data Acquisition (SCADA) system (e.g., SCADA component 310). Voltage and current magnitudes can be measured and reported to a system operator every few seconds by the SCADA component 310. The SCADA component 310 can provide functions such as data acquisition, control of power plants, and alarm display. The SCADA component can also allow operators at a central control center to perform or facilitate management of energy flow in the power grid system. For example, operators can use a SCADA component (for example using a computer such as a laptop or desktop) to facilitate performance of certain tasks such opening or closing circuit breakers, or other switching operations that might divert the flow of electricity.

[0045] In some examples, the SCADA component 310 can receive measurement data from Remote Terminal Units (RTUs) connected to sensors in the power grid system, Programmable Logic Controllers (PLCs) connected to sensors in the power grid system, or a communication system (e.g., a telemetry system) associated with the power grid system. PLCs and RTUs can be installed at power plants, substations, and the intersections of transmission and distribution lines, and can be connected to various sensors, including the voltage sensor 302 and the current sensor 304. The PLCs and RTUs receive its data from the voltage and current sensors to which they are connected. The PLCs and RTUs can convert the measured information to digital form for transmission of the data to the SCADA component. In example embodiments, the SCADA component 310 can also comprise central host server or servers called master terminal units (MTUs), sometimes also referred to as a SCADA center. The MTU can also send signals to PLCs and RTUs to control equipment through actuators and switchboxes. In addition, the MTU can perform controlling, alarming, and networking with other nodes, etc. Thus, the SCADA component 310 can monitor the PLCs

and RTUs, and can send information or alarms back to operators over telecommunications channels.

[0046] The SCADA component 310 can also be associated with a system for monitoring or controlling devices in the power grid system, such as an Energy Management System (EMS). An EMS can comprise one or more systems of computer-aided tools used by operators of the electric power grid systems to monitor, control, and optimize the performance of the generation or transmission system. Often, an EMS is also referred to as SCADA/EMS or EMS/SCADA. In these respects, the SCADA/EMS or EMS/SCADA can also perform the functions of a SCADA. Or, a SCADA can be operable to send data (e.g., SCADA data) to the EMS, which can in turn provide the data to the EDM module 316. Other systems with which the EDM module 316 can be associated can comprise a situational awareness system for the power grid system, a visualization system for the power grid system, a monitoring system for the power grid system or a stability assessment system for the power grid system.

[0047] The SCADA component 310 can generate or provide SCADA data (e.g., SCADA DATA shown in FIG. 3) comprising, for example, real-time information (e.g., real-time information associated with the devices in the power grid system) or sensor information (e.g., sensor information associated with the devices in the power grid system) that can be used by the EDM module 316. The SCADA data can be stored, for example, in a repository 314 (described further below). In example embodiments, data determined or generated by the SCADA component 310 can be employed to facilitate generation of topology data (topology data is further described below) that can be employed by the EDM module 316 for enhanced disturbance management, which is further described below.

[0048] The employment of current sensor 304 and voltage sensor 302 allow for fast response. Traditionally, the SCADA component 310 monitors power flow through lines, transformers, and other components relies on the taking of measurements every two to six seconds, and cannot be used to observe the dynamic characteristics of the power system because of its slow sampling rate (e.g., cannot detect the details of transient phenomena that occur on timescales of milliseconds (one 60 Hz cycle is 16 milliseconds)). Additionally, although SCADA technology enables some coordination of transmission among utilities, the process can be slow, especially during emergencies, with much of the response based on telephone calls between human operators at the utility control centers. Furthermore, most

PLCs and RTUs were developed before industry-wide standards for interoperability were established, and as such, neighboring utilities often use incompatible control protocols.

[0049] The measurement device 220 also includes one or more PMUs 306. A PMU 306 can be a standalone device or may be integrated into another piece of equipment such as a protective relay. PMUs 306 can be employed at substations, and can provide input into one or more software tools (e.g., WAMS, SCADA, EMS, and other applications). A PMU 306 can use voltage and current sensors (e.g., voltage sensors 302, current sensors 304) that can measure voltages and currents at principal intersecting locations (e.g., substations) on a power grid using a common time source for synchronization, and can output accurately time-stamped voltage and current phasors. The resulting measurement is often referred to as a synchrophasor (although the term synchrophasor refers to the synchronized phasor measurements taken by the PMU 306, some have also used the term to describe the device itself). Because these phasors are truly synchronized, synchronized comparison of two quantities is possible in real time, and this time synchronization allows synchronized real-time measurements of multiple remote measurement points on the grid.

[0050] In addition to synchronously measuring voltages and currents, phase voltages and currents, frequency, frequency rate-of-change, circuit breaker status, switch status, etc., the high sampling rates (e.g., 30 times a second) provides "sub-second" resolution in contrast with SCADA-based measurements. These comparisons can be used to assess system conditions-such as: frequency changes, power in megawatts (MW), reactive power in mega volt ampere reactive (MVARs), voltage in kilovolts (KV), etc. As such, PMU measurements can provide improved visibility into dynamic grid conditions and can allow for real-time wide area monitoring of power system dynamics. Further, synchrophasors account for the actual frequency of the power delivery system at the time of measurement. These measurements are important in alternating current (AC) power systems, as power flows from a higher to a lower voltage phase angle, and the difference between the two relates to power flow. Large phase angle differences between two distant PMUs can indicate the relative stress across the grid, even if the PMUs are not directly connected to each other by a single transmission line. This phase angle difference can be used to identify power grid instability, and a PMU can be used to generate an angle disturbance alarm (e.g., angle difference alarm) when it detects a phase angle difference.

[0051] Examples of disturbances that might cause the generation of an angle disturbance alarm can comprise, for example, a line out or line in disturbance (e.g., a line out disturbance in which a line that was in service has now gone out of service, or in the case of a line in disturbance, in which case a line that was out of service has been brought back into service). PMUs 306 can also be used to measure and detect frequency differences, resulting in frequency alarms being generated. As an example, unit out and unit in disturbances can result in the generation of a frequency alarm (e.g., a generating unit was in service, but might have gone out of service, or a unit that was out of service has come back in to service--both can cause frequency disturbances in the system that can result in the generation of a frequency alarm.). Still yet, PMUs 306 can also be used to detect oscillation disturbances (e.g., oscillation in the voltage, frequency, real power--any kind of oscillation), which can result in the generation of an alarm (e.g., oscillation alarm). Several other types of alarms can be generated based on PMU data from PMU based measurements. Although the disturbances mentioned (e.g., line in/out, unit in/out, load in/out) can result in angle or frequency disturbance alarms, an angle or frequency disturbance alarm might not necessarily mean that a particular type of disturbance occurred, only that it is indicative of that type of disturbance. For example, if a frequency disturbance alarm is detected, it might not necessarily be a unit in or unit out disturbance, but may be a load in or load out disturbance. The measurement requirements and compliance tests for a PMU 306 have been standardized by the Institute of Electrical and Electronics Engineers (IEEE), namely IEEE Standard C37.118.

[0052] In the example of FIG. 3, one or more Phasor Data Concentrators (PDCs) 312 are shown, which can comprise local PDCs at a substation. Here, PDCs 312 can be used to receive and time-synchronized PMU data from multiple PMUs 306 to produce a real-time, time-aligned output data stream. A PDC can exchange phasor data with PDCs at other locations. Multiple PDCs can also feed phasor data to a central PDC, which can be located at a control center. Through the use of multiple PDCs, multiple layers of concentration can be implemented within an individual synchrophasor data system. The PMU data collected by the PDC 312 can feed into other systems, for example, a central PDC, corporate PDC, regional PDC, the SCADA component 310 (optionally indicated by a dashed connector), energy management system (EMS), synchrophasor applications software systems, a WAMS, the EDM module 316, or some other control center software system. With the very high sampling rates (typically 10 to 60 times a seconds) and the large number of PMU installations at the substations that are streaming data in real time, most phasor acquisition systems

comprising PDCs are handling large amounts of data. As a reference, the central PDC at Tennessee Valley Authority (TVA), is currently responsible for concentrating the data from over 90 PMUs and handles over 31 gigabytes (GBs) of data per day.

[0053] In this example, the measurement device 220, the SCADA component 310, and PDCs/Central PDCs 312, can provide data (e.g., real-time data associated with devices, meters, sensors or other equipment in the power grid system) (including SCADA data and topology data), that can be used by the EDM module 316 for enhanced disturbance management. Both SCADA data and PMU data can be stored in one or more repositories 3014. In some example embodiments, the SCADA data and PMU data can be stored into the repository 314 by the SCADA component 310, or by the PDC 412. In other embodiments, the EDM module 316 can have one or more components or modules that are operable to receive SCADA data and PMU data and store the data into the repository 314 (indicated by dashed lines). The repository can comprise a local repository, or a networked repository. The data on the repository 314 can be accessed by SCADA component 310, the PDCs 312, others systems (not shown), and optionally by example embodiments of the EDM module 316. In example embodiments, the EDM module 316 can be operable to send instructions to one or more other systems (e.g., SCADA component 310, PDCs 312) to retrieve data stored on the repository 314 and provide it to the EDM module 316. In other embodiments, the EDM module 316 can facilitate retrieval of the data stored in repository 314, directly.

[0054] In example embodiments, the data stored in the repository 314 can be associated SCADA data and PMU data. The data can be indicative of measurements by measurement device 220 that are repeatedly obtained from a power grid system. In example embodiments, the data in repository 314 can comprise PMU/SCADA-based equipment data, such as, for example, data associated with a particular unit, line, transformer, or load within a power grid system (e.g., power grid system 200). The data can comprise voltage measurements, current measurements, frequency measurements, phasor data (e.g., voltage and current phasors), etc. The data can be location-tagged. For example, it can comprise a station identification of a particular station in which a power delivery device being measured is located (e.g., "CANADA8"). The data can comprise a particular node number designated for a location. The data can comprise the identity of the measure equipment (e.g., the identification number of a circuit breaker associated with an equipment). The data can also be time-tagged, indicating the time at which the data was measured by a measurement device. The PMU/SCADA-based equipment data can also contain, for example, information

regarding a particular measurement device (e.g., a PMU ID identifying the PMU from which measurements were taken).

[0055] In example embodiments, the data stored in repository 314 can comprise not only collected and measured data from various measurement devices 220, the data can also comprise data derived from that collected and measured data. The data derived can comprise topology data (e.g., PMU/SCADA-based topology data), event data, and event analysis data, and EDM data (data generated by EDM module 316).

[0056] In example embodiments, the repository 314 can contain topology data (e.g., PMU/SCADA-based topology data) indicative of a topology for the power grid system 200. The topology of a power grid system can relate to the interconnections among power system components, such as generators, transformers, busbars, transmission lines, and loads. This topology can be obtained by determining the status of the switching components responsible for maintaining the connectivity status within the network. The switching components can be circuit breakers that are used to connect (or disconnect) any power system component (e.g., unit, line, transformer, etc.) to or from the rest of the power system network. Typical ways of determining topology can be by monitoring of the circuit breaker status, which can be done using measurement devices and components associated with those devices (e.g., RTUs, SCADA, PMUs). It can be determined as to which equipment has gone out of service, and actually, which circuit breaker has been opened or closed because of that equipment going out of service.

[0057] The topology data can be indicative of an arrangement (e.g., structural topology, such as radial, tree, etc.) or a power status of devices in the power grid system. Connectivity information or switching operation information originating from one or more measurement devices 220 can be used to generate the topology data. The topology data can be based on a location of devices in the power grid system, a connection status of devices in the power grid system or a connectivity state of devices in the power grid system (e.g., devices that receive or process power distributed in throughout the power grid system, such as transformers and breakers). For example, the topology data can indicate where devices are located, and which devices in the power grid system are connected to other devices in the power grid system (e.g., where devices in the power grid system are connected, etc.) or which devices in the power grid system are associated with a powered grid connection. The topology data can further comprise the connection status of devices (e.g., a transformer, etc.)

that facilitate power delivery in the power grid system, and the statuses for switching operations associated with devices in the power grid system (e.g., an operation to interrupt, energize or de-energize or connect or disconnect) a portion of the power grid system by connecting or disconnecting one or more devices in the power grid system (e.g., open or close one or more switches associated with a device in the power grid system, connect or disconnect one or more transmission lines associated with a device in the power grid system etc.). Furthermore, the topology data can provide connectivity states of the devices in the power grid system (e.g., based on connection points, based on busses, etc.).

[0058] In example embodiments, the repository 314 can contain a variety of event and event analysis data, which can be derived based on PMU data, and in some embodiments, other data as well (e.g., SCADA data, other measurement data, etc.). The data can comprise information regarding events related to the power grid system 200. An event can comprise, for example, one or more disturbances to the power grid system. A disturbance can comprise, for example, a line disturbance (e.g., line in, or line out), a unit disturbance (e.g., unit in or unit out), or load disturbance (load in or load out). For each event, relevant information such as the station where the event occurred, the voltage level associated with the station (e.g., 500 kV), the node number related to the event, the equipment related to the event, the change in real and reactive power, and change in voltage per unit for the event. The event and event analysis data can also comprise EDM data, which can be data related to events. The various data stored in the repository 314, including equipment data, topology data, event data, event analysis data, EDM data, and other data, can be inputs into the various functionalities and operations that can be performed by the EDM module 316.

[0059] FIG. 4 illustrates an Automatic Model Validation (AMV) framework 400 for validating power system models in accordance with an example embodiment. In this example, the framework 400 may be a framework that implements or otherwise includes an EDM component such as EDM module 316 shown in FIG. 3. In this example, the AMV framework includes a disturbance event detection module 410, a PMU selection module 411, a tag mapping module 412, a data file collection module 413, a subsystem definition module 414, a model validation module 415, and a reporting module 416.

[0060] In response to an alarm, for example, when a PMU-based alarm is detected (e.g., an angle difference alarm or frequency disturbance alarm) the disturbance event detection module 410 of the EDM can respond to the alarm by correlating the alarm with the

change in topology (e.g., topology data such as equipment energization status, equipment connection status, etc.) of the system that potentially gave rise to that alarm. This correlation of PMU, equipment data, and topology data can provide context to an alarm, and can be used to associate information with the event that comprises the following: a disturbance epicenter; a disturbance magnitude; a disturbance impact; and an event spread. The disturbance epicenter comprises information about the detection time of an event along with the epicenter of the event, including the exact cause (e.g., characterization) and location (e.g., localization) of the event, wherein an event can be comprised of one or more disturbances. In an event, a disturbance at one location can lead to a disturbance at another location, and so on. The disturbance event detection module 410 can attempt to determine a cause and categorize the disturbance as a line in/out, unit in/out, or load in/out, and also provide a coherency indicator that indicates how likely the disturbance is of a particular characterization. To characterize a disturbance (or determine a cause for the disturbance, classify the disturbance, etc.) PMU data can be correlated with other data, such as SCADA data, which includes topology data. PMUs are monitoring the effect of something that happened on the grid (e.g., an angle disturbance alarm or a frequency disturbance alarm). SCADA data can provide information on the topology (e.g., topology data, e.g., where the unit, line, or a transformer, and what circuit breaker is connected or involved), and how the topology reacted to a disturbance (e.g., what are the topological changes that have taken place).

[0061] The disturbance event monitoring module 410 can also provide a coherency indicator that indicates how likely the disturbance is of a particular characterization. As mentioned above, PMU-based data can result in the generation an angle disturbance alarm, and can also generate a frequency disturbance alarm. As an example, if a frequency disturbance alarm is generated, and the disturbance event monitoring module 410 correlates the PMU alarm with a change in topology that indicated that a unit has come out of service, this correlation is high because generating unit trips can cause a frequency alarm. The coherency is thus indicated as high for frequency because the PMU alarm and the topology change both match well with a cause (unit out) and effect (frequency alarm). The disturbance event monitoring module 410 can account for multiple scenarios. As another example, if a line has tripped, this disturbance will probably increase the angle separation across the line, but would not necessarily cause a frequency alarm. If an angle disturbance alarm has been generated, and the topology change shows that a line's status is that it has come out of

service, the PMU angle disturbance alarm correlates highly with the topology change that took place, and thus the coherency for the angle disturbance alarm can be indicated as high.

[0062] An event can also comprise more than one disturbances, in which all the disturbances are part of one event. PMU detections (e.g., measurements) can result in the generation of alarms, and the continued generation of alarms for the same event. The disturbance event monitoring module 410 of the EDM can utilize the topology data (e.g., the equipment status, the breaker status, the topology exchanged etc.) to determine if the disturbances are part of the same event. If in the subsequent cycles the topology does not change any more, despite still receiving new alarms, then that might be an indication that the same disturbances that are resulting the continuous generation of the alarms (e.g., as opposed to different disturbances associated with a different event impacting other locations). Overlapping (e.g., correlating, overlaying) the topology changes on top of the PMU based alarms can thus be a way to validate the alarms that are coming from the PMUs; PMU based alarms would still be generated, when there really are no more disturbances after a period of time.

[0063] The information about the disturbance epicenter can be at a granularity level that comprises information regarding the epicenter of an event, for example, the disturbance type, the equipment, the circuit breaker, the name or designation of the station, the voltage level associated with the station (e.g., 500 kV), and the name or designation of the node. The information can be derived from using, for example, PMU data, SCADA Data, and topology data. As mentioned, differences in, for example, angle, frequency, etc. can inform as to whether there is a disturbance event, which might be a line in/out, unit in/out, or load in/out, each of which can lead to an impact on certain electrical parameters, comprising, for example, change in real power, reactive power, frequency, and voltage per unit. Time synchronized information reported by the measurement devices can be used to determine which equipment was impacted first in time. Topology information can be used to determine whether other equipment (including at other stations or nodes) connected with the equipment that was impacted first in time also experienced a disturbance. An event can comprise one or more disturbances. The disturbance event monitoring module 410 can use topology information and time synchronized information, to determine that several equipment all connected together experienced a disturbance, and that one equipment was impacted first, and then a second equipment connected to the first one experienced a disturbance next, then a

third equipment connected to the second. By making these determinations, an epicenter--the source of the event--can be determined.

[0064] In addition to determining the characterization of a disturbance, location of a disturbance, and epicenter of a disturbance, the disturbance event monitoring module 410 can also be operable to provide a disturbance magnitude for each disturbance. At the point of each disturbance, during the transition from pre-disturbance state to post-disturbance state, disturbance magnitude information comprising information about the change in electrical parameters (e.g. change in real power, change in reactive power, and change in voltage) can be determined by the disturbance event monitoring module 410. The magnitude information can be for the disturbance epicenter, for example. The magnitude information can also be for the most impacted PMU location, for example.

[0065] The disturbance event monitoring module 410 can also be operable to determine disturbance impact information, which can comprise information about the impact of the disturbance event at pre-specified and measured key locations in the system using a disturbance impact factor (DIF) metric, which can be a function of the change in power, voltage, real power, reactive power, and voltage, or some other parameter (e.g., electrical parameter, custom-designed parameter, etc.) with reference to the point of disturbance. The DIF reflects the impact of each disturbance in an event on a PMU location (based on user defined weights and steady-state changes in the power system parameters during the disturbance), and can be derived, for example, by using the example equation below:

$$\begin{aligned} \text{DIF}_{\text{PMU Bus } i} &= W_1 * \frac{\Delta P_{\text{PMU Bus } i}}{\Delta P_{\text{Disturbance Bus } i}} + W_2 * \frac{\Delta Q_{\text{PMU Bus } i}}{\Delta Q_{\text{Disturbance Bus } i}} + W_3 \\ &\quad * \frac{\Delta V_{\text{PMU Bus } i}}{\Delta V_{\text{Disturbance Bus } i}} \end{aligned}$$

[0066] In this equation, the $\text{DIF}_{\text{PMU Bus } i}$ is the disturbance impact factor associate with a particular PMU. It is calculated, for example, by multiplying weighting factor W_1 multiplied against the change in real power of the PMU over the change in real power of the disturbance location, added to a weighting factor W_2 multiplied against a change in quality Q at the PMU over the change in quality at the disturbance location, added to a weighting factor W_3 multiplied against a change in voltage at the PMU over the change in voltage of the

disturbance location. Each of the weighting factors W1, W2, and W3 can be set (e.g., set by a power systems operator). Again, other factors can be accounted for when calculating a disturbance impact factor, which can depend on customer or user choice or design.

[0067] The disturbance event monitoring module 410 can also be operable to determine event spread information. Event spread information can comprise information about the spread or scope of the event (e.g., whether the event is a local event or a wide area event). A local event can be an event wherein only one location (e.g., one substation) is impacted, whereas a wide-spread event can be an event in which multiple locations have been impacted. Event spread information can also include information as to whether the event involves different types of equipment (e.g., a line and a load simultaneously, etc.).

[0068] When a new event (comprising of one or more disturbances) takes place, each new disturbance may be appended to an event history archive in a chronological manner, which can enable a post-event analysis to be performed. The information archived for each disturbance can be as follows: event detection time; correlation of system topological disturbances in the event with PMU-based alarms; disturbance type, location, and magnitude; most impacted location (amongst the pre-specified list of key locations) due to the disturbance.

[0069] According to various embodiments, the PMU selection module 411 may select or otherwise identify PMUs on the electrical grid which are affected by a disturbance event. For example, the PMU selection module 411 may identify PMUs that see adequate disturbance information which can be used for performing model validation of a device (generator, transmission system, load, etc.) which is associated with the PMU. For each of the selected PMUs, the PMU selection module 411 may determine whether there is a need to proceed to model validation. For example, the PMU selection module 411 may compare a disturbance impact factor of a selected PMU to a predefined threshold. In this example, if the DIF is greater than the threshold, the PMU selection module 411 may select the PMU (and its related device(s)) as a candidate for model validation. As another example, the PMU selection module 411 may execute a machine learning algorithm to compare the features of the event and the associated network topology with features of existing events in a database. Here, if the similarity is high enough, the PMU selection module 411 may determine the need for model validation.

[0070] When the PMUs associated with the disturbance event have been identified, the tag mapping module 412 may correlate a tag of an identified PMUs with a tag of one or more power system nodes on the electrical grid. Normally, a unique generator may be uniquely defined by both the generator name and the name of the station it is directly tied to. The needs for a tag mapping function arises from the potentially different naming conventions from three different entities. Typically, the names of power system nodes such as generators, substations, etc., are defined by a generator owner (GO), while their corresponding names in the EMS are defined by the utilities. Meanwhile, the names of the PMU and related substation/generators are defined by a third party-regional transmission owner (RTO), which is more recently than the previous two. The name convention for power system node tags in EMS is typically limited in size (*e.g.*, 8 bits, etc.), while the names in the RTO's PMU database tends to have more flexibility allowing for larger-sized tag names. In this case, there may be three different names for one generator in the three different databases: utility's EMS, Generator Owner's asset database and RTO's PMU database. Because the names are different, the PMU tags must be mapped to power system node tags to associate the event disturbance data captured by the PMU with one or more elements on the power grid (generator, substation, etc.). The tag mapping module 412 of the example embodiments performs an automated tag-mapping process to automatically associated the selected PMUs with corresponding subsystems on the electrical grid.

[0071] According to one example, the auto tag mapping process from EMS system to RTO's PMU database is described here. after the identification of grid event and selection of PMU and the affected station from EMS (as described in step 410 and 411 in Fig. 4), Substation names may be retrieved for the EMS system, and PMU names may be retrieved from a RTO's PMU database. Name variants of the generator and the station may be generated for pairs by the tag mapping module 412 based on a database or predefined location dictionary. The name variants are also called name augmentation. The augmented name may then be correlated to the names in the ROT's PMU database based on the word, term and contextual association between word and terms. The similarity-based metrics such as cosine similarity between the word and terms can be used. A correlation vector may be used for each pair of PMU and EMS system, and the highest correlated matched pair is the mapping result. Other approaches like rule-based inference, fuzzy logic can also be used to facilitate the mapping decision. Results of the tag mapping may be output to the user

interface 430 to enable a user to review and correct mapping results. Furthermore, mapped pairs may be added to a database (*e.g.*, AMV database 420) for future use.

[0072] The data file collection module 413 may establish connections with existing databases and retrieve naming information, power system model information, network topology information, and the like, which can be used by the different components of the EDM shown in FIG. 4. For example, FIG. 5 shows an example of an architecture of a file collection system (AMV module 536) which further includes elements from the EDM incorporated therein for performing automated power system model validation. In this example, the AMV module 536 may include or otherwise be connected to the file collection system 413 shown in FIG. 4.

[0073] Referring to FIG. 5, current and voltage sensors 510 may acquire voltage data, current data, and the like, from the electrical grid. The data may be based on RTUs 512, PMUs 514, SCADA 516, PDC 518, and the like. The AMV module 536 may identify and retrieve PMU data for a period of time associated with the detected disturbance. The onset and clearing of disturbances may be performed on a regular basis. Once a disturbance time period is identified, the AMV module 536. The AMV module 536 may retrieve synchrophasor data from the synchrophasor repository 526 to identify only power system nodes where disturbances are observed and whose dynamic model can be validated.

[0074] A network topology model may be retrieved by the AMV 536 in this example. Here, the AMV 536 may include the data file collection module 413 shown in FIG. 4. Furthermore, disturbance information from disturbance monitoring 524, enhanced disturbance monitoring 532 (synched using data stored in synchrophasor repository 526) may be retrieved by the AMV 536. In this example, the AMV 536 interconnects with existing storage modules of a power system. The EDM may export a time-stamped, topology solved model (power system model) from the EMS topology-solved network model repository 530. The network model may be in a standard format (CIM, PSS/e, etc.) and may be a format of the network at the time the disturbance is detected. Meanwhile, a dynamic model may be retrieved as well. For example, an EMS that is armed to run real-time transient stability may have a dynamic model repository 534 which can be configured to pick dynamic models from a preconfigured network location. In some embodiments, the model validation module 415, the reporting module 416, or the like, from the system 400 may provide subscription services for other entities such as GOs, TSOs, RTOs, and the like. The subscription services may

provide calibration information, tag-mapping information, PMU information, and the like, to the other systems that operate and have interest in the electrical power grid.

[0075] The subsystem definition module 414 may carve out which subsystems (generators, substations, etc.) should have power system models validated. Here, the subsystem module 414 may carve out and identify the subsystems based on PMU selection and tag mapping that is performed by the PMU selection module 411 and the tag mapping module 412. Furthermore, the power system models collected by the file collection unit 413 may associated with the subsystems for validation and calibration.

[0076] In this example, the model validation module 415 may automatically determine whether a power system model of a subsystem (power system node) is valid. For example, the model validation module 415 may receive disturbance data monitored by one or more PMUs coupled to an electrical power distribution grid may be received. The disturbance data can include voltage (" V "), frequency (" f "), and/or active and nonactive reactive (" P " and " Q ") power measurements from one or more points of interest (POI) on the electrical power grid. A playback simulation using default model parameters and existing transient simulation software can be performed. These default parameters can be the current parameters incorporated in the power system model. The current parameters can be stored in a model parameter record. The simulation can be done by a power system simulation engine, including GE PSLF, Power Tech TSAT and Siemens PIT PSS/E, to perform a real-time power system simulation scenario.

[0077] The model validation module 415 may also comprise of the model calibration unit with three functionalities. The first functionality is an event screening tool to select characteristics of disturbance event from a library of recorded event data. This functionality clusters similar events and determines the set of most representative events from the available measurements. The second functionality is a preconditioning tool for the parameter identifiability study. When implementing this functionality, a global quantification of parameter sensitivity magnitude and dependency will be achieved. The third functionality is a tool for simultaneous tuning of models using an augmented event comprised of multiple events.

[0078] In accordance with some embodiments, event screening can be implemented during the simulation to provide computational efficiency. If hundreds of events are stitched together and fed into the calibration algorithm unselectively, the algorithm may not be able to

converge. To maintain the number of events manageable and still keep an acceptable representation of all the events, a screening procedure may be performed to select the most characteristic events among all. Depending on the type of events, the measurement data could have different characteristics. For example, if an event is a local oscillation, the oscillation frequency in the measurement data would be much faster as compared to an inter-area oscillation event. In some implementations, a K-medoids clustering algorithm can be utilized to group events with similar characteristic together, thus reducing the number of events to be calibrated.

[0079] The results of the simulated default model performance can be compared by the model validation module 415 to actual disturbance data measured on the power system. If the default model performance is within (*e.g.*, equal to or less than) a predetermined threshold of accuracy (*e.g.*, specified by, for example, power system operators, designers, *etc.*), the model validation module 415 can end parameter conditioning and wait for disturbance data from a subsequent event.

[0080] If the default model performance is outside of the predetermined threshold, a parameter identifiability algorithm may be performed. In accordance with some embodiments, the parameter identifiability analysis can determine the differing effects that various parameters can have on power system model. In some implementations, each parameter can represent a factor/coefficient in a term of a polynomial expression representing the power system model. To decide which parameters of the power system model are the best choice to tune, a parameter sensitivity study may be performed. The sensitivity study can vary the value of the parameter, compare the power system model result to monitored data, and then determine the perturbation's magnitude caused by the variation in parameter value. To calculate the model's sensitivity to each parameter, playback simulation is conducted with the value of that parameter perturbed upward and downward. The difference in the model's performance (*i.e.*, when compared to the measured disturbance data) between the up, and the down perturbation yields the trajectory sensitivity matrix.

[0081] In accordance with some embodiments, the parameter identifiability analysis addresses two aspects: (a) magnitude of sensitivity of output to parameter change; and (b) dependencies among different parameter sensitivities. For example, if the sensitivity magnitude of a particular parameter is low, the parameter would appear in a row being close to zero in the parameter estimation problem's Jacobian matrix. Also, if some of the

parameter sensitivities have dependencies, it reflects that there is a linear dependence among the corresponding rows of the Jacobian. Both these scenarios lead to singularity of the Jacobian matrix, making the estimation problem infeasible. Therefore, it may be important to select parameters which are highly sensitive as well as result in no dependencies among parameter sensitivities. Next, parameter values in the active power system model may be updated, and the system may generate a report and/or display of the estimated parameter values(s), confidence metrics, and the model error response as compared to the measured data.

[0082] The reporting module 416 may notify a user (via user interface 430) of the validity of a power system model that is determined by the EDM system. For example, the reporting module 416 may notify that a power system model is valid, invalid, and the like. As another example, the reporting module 416 can provide additional information about a power system model. For example, the reporting module 416 may provide an update (to one or more parameters) of the power system model to be accepted by the user via the user interface 430. In this case, the reporting module 416 can retrieve updated parameter information from the model validation module 415 and provide those to the user interface 430 to efficiently update a power system model on behalf of a user.

[0083] In some embodiments, the model validation module 415, the reporting module 416, or the like, from the system 400 may provide subscription services for other entities such as GOs, TSOs, RTOs, and the like. The subscription services may provide calibration information, tag-mapping information, PMU information, and the like, to the other systems that operate and have interest in the electrical power grid.

[0084] The system shown in FIG. 4 further includes an expert system 420 which includes an automated model validation (AMV) database 421 and an inference engine 422. The AMV database 421 may store information that is collected by the EDM such as disturbance information (DIF, PMU selection, tag dictionaries, etc.). Furthermore, reports and results generated by the model validation module 415 may be stored there as well. The inference engine 422 may query a calibrated case and reuse a subsystem, which are stored in the AMV database 421.

[0085] In some embodiments, the inference engine 422 may analyze a parameter change for a mapped power system node and adjust a threshold for the power system node to thereby update a power system model associated therewith. The update may be determined

based on a DIF of a PMU associated with the power system node. The inference engine 422 may provide rules, a knowledge base, and a learning algorithm for tag mapping between selected PMU tags and power system node tags. The inference engine 422 may provide an initial value and other information to accelerate the model validation and calibration. In some embodiments, the inference engine 422 may extract event (disturbance) features, cluster events using similarity with previously detected events, and update clusters based on newly received event information.

[0086] FIG. 6 illustrates a method 600 for determining a predictive CFD flow in accordance with an example embodiment. For example, the method 600 may be performed by a database, a cloud platform, a server, a user device, a combination of devices, and the like. Referring to FIG. 6, in 610, the method may include, in response to an event on an electrical grid, identifying one or more PMUs of the electrical grid based on a geographical location of the event. For example, the one or more PMUs may be identified from a larger group of PMUs based on disturbance impact factor information at each of the PMUs. In this case, PMUs having a DIF greater than a predetermined threshold may be identified/selected as having captured information associated with the disturbance event based on the geographical proximity or location with respect to a location of the event.

[0087] In 620, the method may include mapping the identified PMU to a power system node on the electrical grid based on a tag of the identified PMU and a tag of the power system node. Here, the mapping may include determining a similarity between a name of the identified PMU and respective names of a plurality of power system nodes on the electrical grid, and mapping the identified PMU to a power system node having a name that is most similar to the name of the identified PMU. In some embodiments, the mapping may include automated tag mapping a name of the identified PMU to a name of the power system node defined by an energy management system (EMS).

[0088] In 630, the method may include retrieving a power system model of the power system node, and in 640, the method may include triggering a validation determination of the power system model of the power system node based on event data sensed by the identified PMU. In some embodiments, the method may further include, in response to the triggering, determining whether the power system model of the power system node is to be calibrated based on a simulation of a default parameters of the power system model with respect to the event data sensed by the identified PMU. In some embodiments, the method may further

include, in response to determining the power system model should be calibrated, identifying changes in values to one or more parameters of the power system model and outputting the identified changes in values for display via a user interface. For example, the power system model of the power system node may include one or more of a representation of transmission system components on the electrical grid, a representation of power generating components on the electrical grid, and a load representation at various locations on the electrical grid

[0089] FIG. 7 illustrates a computing system 700 that may be used in any of the methods and processes described herein, in accordance with an example embodiment. For example, the computing system 700 may be a database node, a server, a cloud platform, or the like. In some embodiments, the computing system 700 may be distributed across multiple computing devices such as multiple database nodes. Referring to FIG. 7, the computing system 700 includes a network interface 710, a processor 720, an input / output 730, and a storage device 740 such as an in-memory storage, and the like. Although not shown in FIG. 7, the computing system 700 may also include or be electronically connected to other components such as a display, an input unit(s), a receiver, a transmitter, a persistent disk, and the like. The processor 720 may control the other components of the computing system 700.

[0090] The network interface 710 may transmit and receive data over a network such as the Internet, a private network, a public network, an enterprise network, and the like. The network interface 710 may be a wireless interface, a wired interface, or a combination thereof. The processor 720 may include one or more processing devices each including one or more processing cores. In some examples, the processor 720 is a multicore processor or a plurality of multicore processors. Also, the processor 720 may be fixed or it may be reconfigurable. The input / output 730 may include an interface, a port, a cable, a bus, a board, a wire, and the like, for inputting and outputting data to and from the computing system 700. For example, data may be output to an embedded display of the computing system 700, an externally connected display, a display connected to the cloud, another device, and the like. The network interface 710, the input / output 730, the storage 740, or a combination thereof, may interact with applications executing on other devices.

[0091] The storage device 740 is not limited to a particular storage device and may include any known memory device such as RAM, ROM, hard disk, and the like, and may or may not be included within a database system, a cloud environment, a web server, or the like. The storage 740 may store software modules or other instructions which can be executed by

the processor 720 to perform the method shown in FIG. 6. According to various embodiments, the storage 740 may include a data store having a plurality of tables, partitions and sub-partitions. The storage 740 may be used to store database records, items, entries, and the like.

[0092] According to various embodiments, the storage 740 may store information about an event on an electrical grid. For example, the event may be detected by the processor 720 based on a disturbance in one or more of power, voltage, and current on the electrical grid. The processor 720 may, in response to the event being detected, identify one or more PMUs of the electrical grid which have data of the event based on a geographical location of the event. Furthermore, the processor 720 may map the identified PMU to a power system node on the electrical grid based on a tag of the identified PMU and a tag of the power system node, and retrieve a power system model of the power system node from a repository. Furthermore, the processor 720 may trigger a validation determination of the power system model based on event data sensed by the identified PMU.

[0093] In some embodiments, the processor 720 may identify one or more PMUs affected by the event based on a disturbance impact factor at the one or more PMUs being greater than a predetermined threshold. In some embodiments, the processor 720 may determine a similarity between a name of the identified PMU and respective names of a plurality of power system nodes on the electrical grid, and map the identified PMU to a power system node having a name that is most similar to the name of the identified PMU. For example, the processor 720 may auto-tag map a name of the identified PMU to a name of the power system node defined by an energy management system (EMS).

[0094] In response to the triggering, the processor 720 may execute an automated power system model validation. For example, the processor 720 may determine whether the power system model of the power system node is to be calibrated based on a simulation of a default parameters of the power system model with respect to the event data sensed by the identified PMU. In some embodiments, in response to determining the power system model should be calibrated, the processor 720 may identify changes in values to one or more parameters of the power system model and output the identified changes in values for display via a user interface. In some embodiments, the power system model of the power system node may include a representation of transmission system components on the electrical grid, a representation of power generating components on the electrical grid, and a load representation at various locations on the electrical grid.

[0095] FIG. 8A illustrates a process 800 of tag-mapping in accordance with an example embodiment. Referring to FIG. 8A, three tables are shown that correspond to three separately stored and managed data stores (802, 804, and 806) which store generator information and its connected station information. As can be seen, each row in EMS data table 802, PMU point of interest data table 804, and general information data table 806, characterizes a unique generator device name and its station name. For example, the first row in EMS data table 802 represents the generator device named with “ABCD” directly tied to Station “W_SHORE”. And the second row in EMS data table 802 represents the generator device named with “EFGH” directly tied to the same Station “W_SHORE”. Note that the name is shorter than 8 character due to historical naming convention reason; also note that by sampling using station name or device could not uniquely identify one single device. They have to be used collectively to uniquely characterize one generator device.

[0096] Referring to the PMU information in PMU POI data table 804, a PMU name and PMU ID may be able to link with different voltage and current sensors. This is because one PMU may have multiple channels, and each channel may measure one power line connecting to one generator device. As an example, one PMU name “ELECTRICRD_A” consists three measurement channels: G345_U1_VP, G345_U2_VP, G345_U3_VP. The general information data table 806 may be stored in the host computer managed by the RTO who also is responsible to define and manage the POI PMU’s Information.

[0097] The goal of tag mapping is to match the identified row (or Station Device) with a certain row in the POI PMU Information. Table 808 shows the mapping result corresponding to the illustrated example from data tables 802, 804, and 806. In this example, the first row of 808 shows that the matched result from device named with “ABCD” linking to a station named with “W_SHORE” have been matched to a PMU Name of “WESTSHORE_A” with a PMU current sensor name of “G115_ABCD_IS”.

[0098] The result of the tag mapping shown in FIG. 8A is that the three data tables 802, 804, and 806, from three differently owned data stores may be mapped together and stored together as a single table 808. In this example, the three tables 802, 804, and 806 become one table 808 that correspond to the mapping. Also, the order of the entries in the tables 802, 804, and/or 806 may change to align the entries together as a result of the tag mapping. For example, in the first row in 808, the device ABCD has been mapped from each of the tables into a same common row. When the tag mapping is performed, there is not

always a direct (exact) match between tags. Rather, the system may perform a similarity analysis to identify most likely matches between the tags in the different tables 802, 804, and 806, for example. In one embodiment, the similarity analysis may be based on term and contextual information of terms which describe the name of a PMU, a generator and a substation. The “term” here may be a keyword, partial name, full name or an abbreviation of the name of a PMU, a generator and a substation. In some embodiments, the tag mapping process may have a function that learns from user inputs. For example, the automatic tag matching may have a mechanism of learning from user input and learning from historical data to help perform the tag mapping and identify similar tags.

[0099] FIG. 8B illustrates a human machine interface 850 for automatic model validation in accordance with an example embodiment. For example, the interface 850 may be output by a system described herein such as AMV module 536 described in FIG. 5. The interface 850 may include tabs or pages for viewing and / or modifying disturbance information, PMU selection information, tag mapping information, file collection information, and subsystem information. In some embodiments, the interface 850 may also include options for validating a power system model and calibrating the power system model in a case the power system model is not valid.

[00100] FIG. 9 illustrates a human machine interface 900 displaying calibration information in accordance with an example embodiment. Referring to FIG. 9, the interface 900 includes user-selectable options of validation, identifiability, and calibration options 910. A customization area 920 allows for selection of a data file (*e.g.*, associated with single or multiple events), a simulation, a calibration algorithm, *etc.* Selection of option (*e.g.*, via touchscreen or computer mouse pointer 940) may result in the optimization criteria (*e.g.*, a baseline approach, a smart weight, a faster solver, an enhanced version, *etc.*). The display may further include graphical charts 940, 950 that show a model response result figure according to the user selected options (*e.g.*, with a percent improvement in accuracy and time marked on the charts 940, 950). The display 900 may also include a table 960 that shows performance in terms of deviation against measurement data, according to the user selected options, with a percentage improvement in accuracy and time included in the table 960. The may also be user-selectable graphical icons allowing a user to visualize parameters 970 and/or export 980 the data.

[00101] FIG. 10 illustrates table data stored in an AMV expert system in accordance with an example embodiment. For example, the AMV expert system may be the AMV module 536 shown in FIG. 5. In this example, a table is shown that represents the data store 1000 that may be stored according to some embodiments. The table may include, for example, entries identifying industrial assets or other systems to be protected. The table may also define fields 1002, 1004, 1006, 1008, 1010, 1012, 1014, 1016, 1018, 1020, 1022, 1024 for each of the entries. The fields 1002, 1004, 1006, 1008, 1010, 1012, 1014, 1016, 1018, 1020, 1022, 1024 may, according to some embodiments, specify: an Event Identifier 1002, an event type 1004, etc. The data store 1000 may be created and updated, for example, when a new physical system is monitored or modeled, a component is to be calibrated, measurement data is received from a measurement unit, etc. The data types are as listed herein.

[00102] Event ID 1002 includes a unique identifier for a grid event stored in the EMS system, which links to a unique start time and time duration.

[00103] Event Type 1004 associates with one type of event including unit in, unit out, line in and line out.

[00104] PMU Location 1006 specifies the name of the station, the voltage level (in unit of Kilovolts) and the Nodes Number (ND).

[00105] PMU ID 1008 includes a unique identifier for the PMU identified and evaluated in the EMS system.

[00106] DIF 1010 is a Disturbance Impact Factor which may be determined as described herein.

[00107] PMU Selection 1012 is determined based on the DIF value and the DIF threshold value. In this example, the DIF threshold is 30%. So the top three rows are selected for model validation while the last row is not selected because its DIF value is lower than the threshold (30%).

[00108] Mapped Generator 1014 is used to indicate the generator name identified according to the auto-tag mapping method.

[00109] Network Model File 1016 is used to indicate the power network model file name identified by the automatic file collection 413 in FIG. 4. It is one input for Model Validation 1022.

[00110] Dynamic Model File 1018 indicates the dynamic model file name (consisting generator model name and parameter value inside) identified by the automatic file collection 413 in FIG. 4. It is one input for Model Validation 1022.

[00111] PMU event File 1020 indicates the PMU event file name identified by the automatic file collection 413 in FIG. 4. It is one input for Model Validation 1022.

[00112] Model Validation 1022 shows the model validation result: either continue to conduct model calibration or no need to conduct model calibration.

[00113] Model Calibration 1024 show the calibrated model file, which should replace the Dynamic model File 1018 after the user's confirmation

[00114] FIG. 11 illustrates a system 1100 that includes an automatic model validation system in accordance with an example embodiment.

[00115] Embodying approaches can account for non-linearity in the power system model; account for multiple differing disturbance events; and calibration results can be localized around assumed default parameter values. Physical constraints of parameters may be enforced during model calibration, and an embodying calibration algorithm avoids tuning model parameters that might already be set at their true (*e.g.*, optimal) values. As shown in FIG. 11, a system 1100 may include a power generation system 1110 in accordance with some embodiments. Furthermore, an embodying AMV system 1120 can include an AMV server 1130 in communication with a server data store 1140.

[00116] The server 1130 can include a server control processor 1131 that communicates with other components of the AMV system 1120. A server control processor 1131 accesses computer executable program instructions, which in some implementations can be stored in the server data store 1140. The server control processor 1131 can support embodying power system model validation for disturbance-based model validation and or calibration by executing executable instructions. Dedicated hardware, software modules, and/or firmware can implement embodying approaches disclosed herein.

[00117] The server 1130 can be in communication with the server data store 1140 directly and/or across an electronic communication network 1118. The electronic communication network 1118 can be, can comprise, or can be part of, an IP network, the Internet, an ISDN, frame relay connections, a modem connected to a phone line, a PSTN, a public or private data network, a LAN, a MAN, a WAN, a wireline or wireless network, a local, regional, or global communication network, an enterprise intranet, any combination of

the preceding, and/or any other suitable communication means. It should be recognized that techniques and systems disclosed herein are not limited by the nature of electronic communication network 1118.

[00118] A power system can include a power generation system 1110, which provides electrical power to an electrical power distribution grid 1112. A PMU 1115 can be coupled to the electrical power distribution grid to monitor signal characteristics (*e.g.*, voltage (V), frequency (f), active reactive power (P), and nonactive reactive power (Q)). The data obtained by the PMU 1115 can be provided to the AMV system 1120 across the electronic communication network 1118. This data can be stored in data records PMU monitored data 1143. It should be readily understood that a power system is not limited to a single power generation system; that an electrical power grid can be a vast, interconnected network of multiple producers (power generation systems), transmission lines, substations, transformers, and loads (power consumers); and that multiple PMUs can be coupled to the power grid at multiple locations.

[00119] Under conventional approaches, a power system model is tuned (“calibrated”) for one event (*e.g.*, treating each disturbance event separately). This conventional approach results in severely limiting that model’s performance to satisfactorily predict a power system’s performance in response to a subsequent event. Because some embodiments described herein simultaneously perform power system parameter tuning across multiple events, these system parameters can be provided to a power system model 1146. By incorporating the tuned parameters into the power system model 1146, the model 1146 can more accurately predict power system performance than conventionally-calibrated (“tuned”) models.

[00120] In accordance with some embodiments, the parameter conditioning tool 1020 generates trajectory sensitivity matrices for all the selected disturbances. These matrices are generated by perturbing each model parameter and feeding the perturbed parameter values to model simulation unit 1133. Depending on the number of disturbances being considered, model calibration algorithm 1144 can follow two options.

[00121] If the number of disturbances is large enough that the union of null spaces of the sensitivity matrices of all the disturbances has a rank higher than the parameter number, an embodying model calibration algorithm 1144 can solve an optimization problem to find a solution that has the minimum total distance to all the null spaces. The solution

reflects the parameter set that has dependencies in one or more of these disturbances. Therefore, such a solution gives a comprehensive identifiability ranking of parameters across disturbances.

[00122] If the number of disturbances is small, a second option can be implemented by model calibration algorithm 1144. This second option evaluates the identifiability of parameters for each disturbance, then calculates the average identifiability ranking across disturbances. Since the sensitivity studies are conducted at the parameters' default values, the parameter conditioning tool can also perform a global sensitivity consistency study when the parameters' values deviate far away from their default values. Such study can portray the geometry of the parameter sensitivity in the entire parameter space.

[00123] In the example of FIG. 11, the server 1130 may include an AMV module 1135 which can conduct the key modules (PMU selection, tag mapping, subsystem definition, model validation). Furthermore, the server data store 1140 may also store a knowledge base for PMU selection 1141 (DIF threshold for each equipment), a knowledge base for tag mapping 1142 such as naming convention rules, naming convention special cases, geographic names repositories, and the like. Meanwhile, the PMU monitored data record 1143 can further include the newly added table record from data store 1000 in FIG. 10, model calibration algorithms 1144, model parameter record 1145, and power system models 1146.

[00124] As will be appreciated based on the foregoing specification, the above-described examples of the disclosure may be implemented using computer programming or engineering techniques including computer software, firmware, hardware or any combination or subset thereof. Any such resulting program, having computer-readable code, may be embodied or provided within one or more non-transitory computer-readable media, thereby making a computer program product, i.e., an article of manufacture, according to the discussed examples of the disclosure. For example, the non-transitory computer-readable media may be, but is not limited to, a fixed drive, diskette, optical disk, magnetic tape, flash memory, semiconductor memory such as read-only memory (ROM), and/or any transmitting/receiving medium such as the Internet, cloud storage, the internet of things, or other communication network or link. The article of manufacture containing the computer

code may be made and/or used by executing the code directly from one medium, by copying the code from one medium to another medium, or by transmitting the code over a network.

[00125] The computer programs (also referred to as programs, software, software applications, “apps”, or code) may include machine instructions for a programmable processor, and may be implemented in a high-level procedural and/or object-oriented programming language, and/or in assembly/machine language. As used herein, the terms “machine-readable medium” and “computer-readable medium” refer to any computer program product, apparatus, cloud storage, internet of things, and/or device (*e.g.*, magnetic discs, optical disks, memory, programmable logic devices (PLDs)) used to provide machine instructions and/or data to a programmable processor, including a machine-readable medium that receives machine instructions as a machine-readable signal. The “machine-readable medium” and “computer-readable medium,” however, do not include transitory signals. The term “machine-readable signal” refers to any signal that may be used to provide machine instructions and/or any other kind of data to a programmable processor.

[00126] The above descriptions and illustrations of processes herein should not be considered to imply a fixed order for performing the process steps. Rather, the process steps may be performed in any order that is practicable, including simultaneous performance of at least some steps. Although the disclosure has been described in connection with specific examples, it should be understood that various changes, substitutions, and alterations apparent to those skilled in the art can be made to the disclosed embodiments without departing from the spirit and scope of the disclosure as set forth in the appended claims.

IN THE CLAIMS:

1. A computing system comprising:
a storage configured to store information about an event on an electrical grid; and
a processor configured to, in response to the event on the electrical grid being detected, identify a phasor measurement unit (PMU) of the electrical grid based on a geographical location of the event, map the identified PMU to a power system node on the electrical grid based on a tag of the identified PMU and a tag of the power system node, and retrieve a power system model of the power system node from a repository,
wherein the processor is further configured to trigger a validation determination of the power system model based on event data sensed by the identified PMU.
2. The computing system of claim 1, wherein the processor is further configured to detect the event on the electrical grid based on a disturbance in one or more of power, voltage, and current, frequency and phase angle.
3. The computing system of claim 1, wherein the processor is configured to identify one or more PMUs affected by the event based on a disturbance impact factor at the one or more PMUs being greater than a predetermined threshold.
4. The computing system of claim 3, wherein the processor is configured to adaptively update the predetermined threshold based on a parameter change in a calibrated result.
5. The computing system of claim 1, wherein the processor is configured to determine a similarity between a name of the identified PMU and respective names of a plurality of power system nodes on the electrical grid, and map the identified PMU to a power system node having a name that is most similar to the name of the identified PMU.
6. The computing system of claim 1, wherein the processor is configured to auto-tag map a generator name and a substation name between a PMU point of interest measurement and EMS measurement, based on term and contextual information of terms which describe the name of a PMU, a generator and a substation.

7. The computing system of claim 1, wherein, in response to the triggering, the processor is further configured to determine whether the power system model of the power system node is to be calibrated based on a simulation of a default parameters of the power system model with respect to the event data sensed by the identified PMU.

8. The computing system of claim 7, wherein, in response to determining the power system model should be calibrated, the processor is configured to identify changes in values to one or more parameters of the power system model and output the identified changes in values for display via a user interface.

9. The computing system of claim 1, wherein the power system model of the power system node comprises one or more of a representation of transmission system components on the electrical grid, a representation of power generating components on the electrical grid, and a load representation at various locations on the electrical grid.

10. The computing system of claim 1, wherein the processor is further configured to connect to an expert system including a database and inference engine.

11. The computing system of claim 10, wherein the database stores calibrated results, associated events, naming convention rules, naming convention special cases, and thresholds for equipment.

12. The computing system of claim 10, wherein the inference engine queries a calibrated case and a reuse subsystem, analyzes parameter changes for a unit and adjusts a threshold for equipment selection based on disturbance impact factor, provide rules, knowledge base and learning algorithms for tag matching, and provides initial values to accelerate model validation and calibration.

13. The computing system of claim 1, wherein the processor is configured to automatically map the identified PMU to the power system node based on a learning mechanism which learns from user input and historical tag mapping data.

14. A method comprising:
in response to an event on an electrical grid, identifying a phasor measurement unit (PMU) of the electrical grid based on a geographical location of the event;
mapping the identified PMU to a power system node on the electrical grid based on a tag of the identified PMU and a tag of the power system node;
retrieving a power system model of the power system node; and
triggering a validation determination of the power system model of the power system node based on event data sensed by the identified PMU.
15. The method of claim 14, further comprising detecting the event on the electrical grid based on a disturbance in one or more of power, voltage, and current.
16. The method of claim 14, wherein the identifying comprises identifying one or more PMUs affected by the event based on a disturbance impact factor at the one or more PMUs being greater than a predetermined threshold.
17. The method of claim 14, wherein the mapping comprises determining a similarity between a name of the identified PMU and respective names of a plurality of power system nodes on the electrical grid, and mapping the identified PMU to a power system node having a name that is most similar to the name of the identified PMU.
18. The method of claim 14, wherein the mapping comprises automated tag mapping a name of the identified PMU to a name of the power system node defined by an energy management system (EMS).
19. The method of claim 14, wherein the mapping comprises auto-tag mapping a generator name and a substation name between a PMU point of interest measurement and EMS measurement, based on term and contextual information of terms which describe the name of a PMU, a generator and a substation.
20. A non-transitory computer-readable medium storing instructions which when executed by a processor cause a computer to perform a method comprising:

in response to an event on an electrical grid, identifying a phasor measurement unit (PMU) of the electrical grid based on a geographical location of the event;

mapping the identified PMU to a power system node on the electrical grid based on a tag of the identified PMU and a tag of the power system node;

retrieving a power system model of the power system node; and

triggering a validation determination of the power system model of the power system node based on event data sensed by the identified PMU.

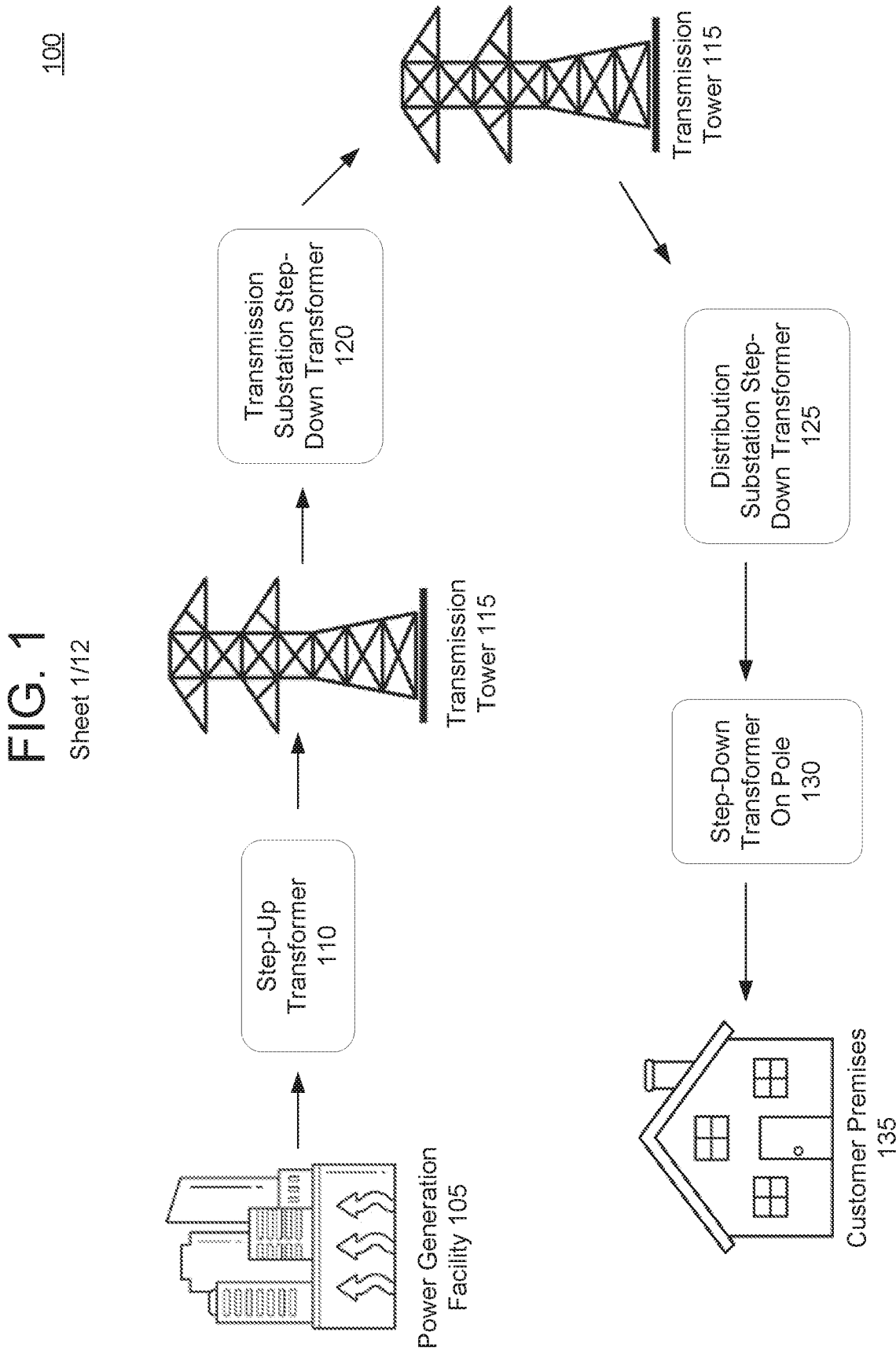
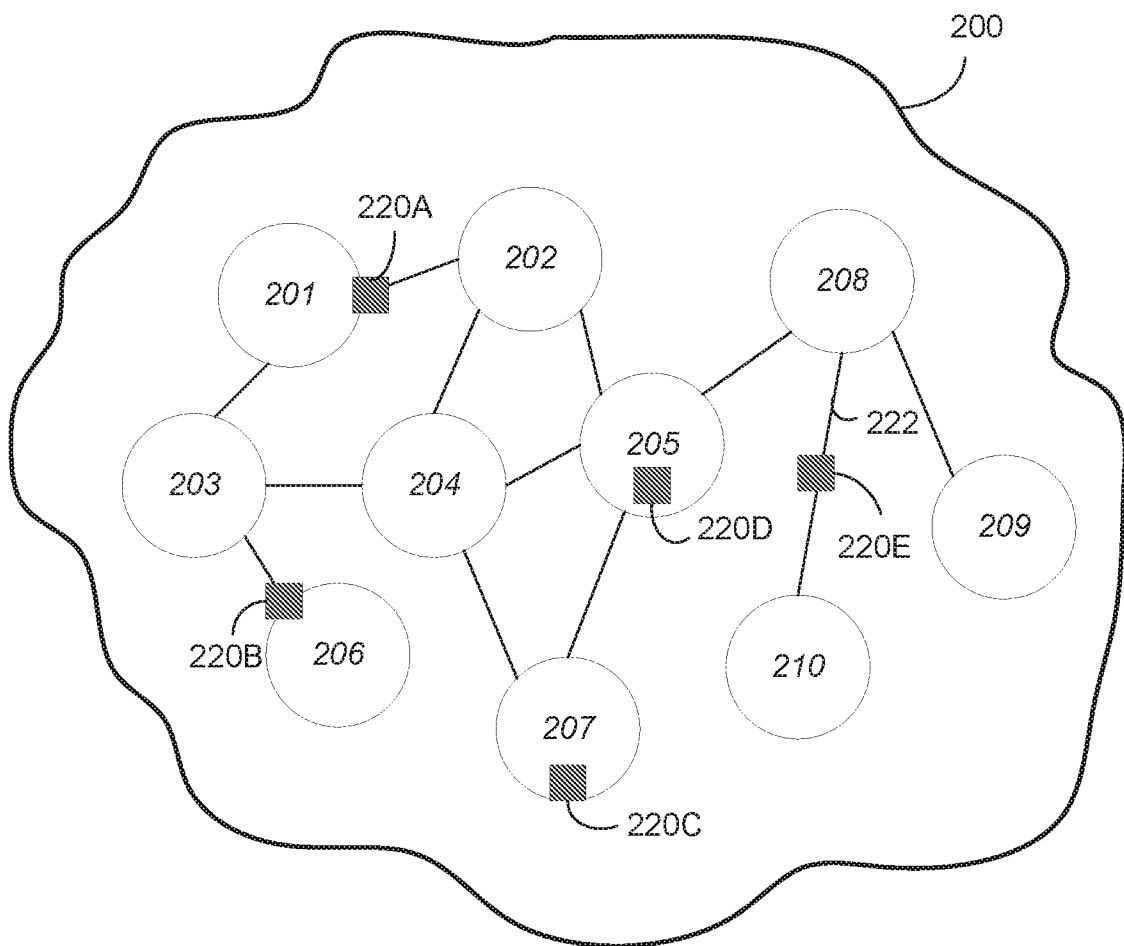


FIG. 2

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300**FIG. 3**

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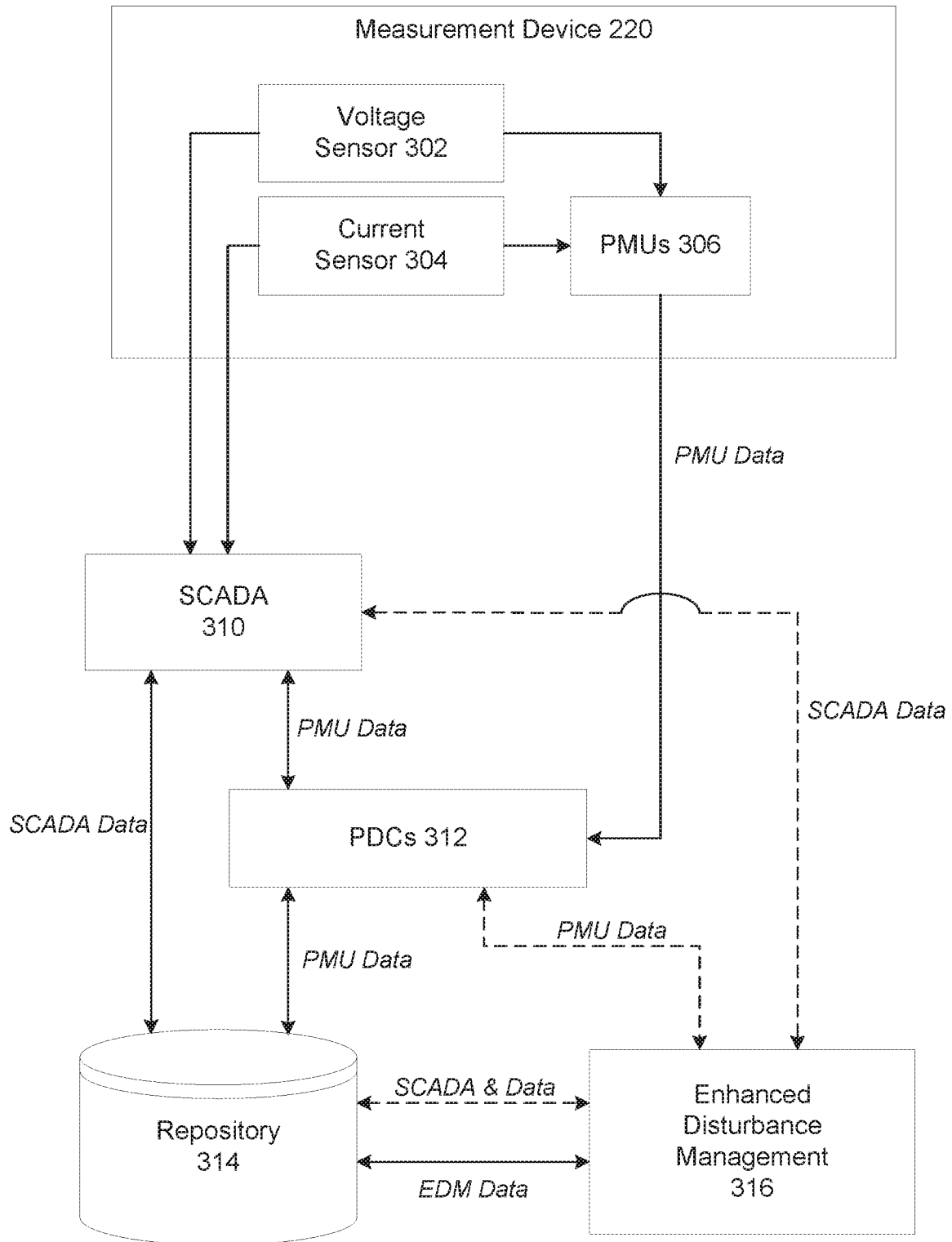


FIG. 4

400

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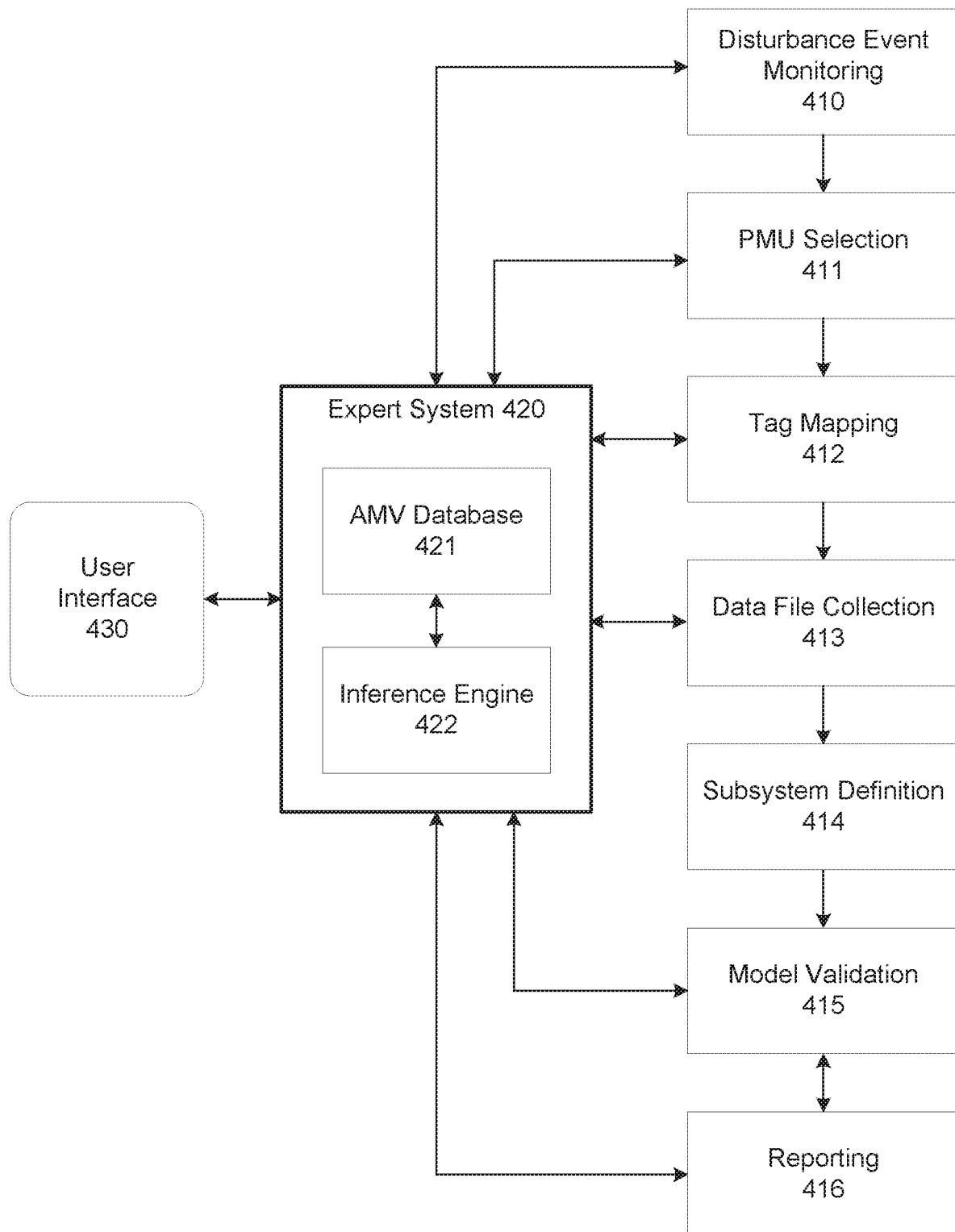


FIG. 5

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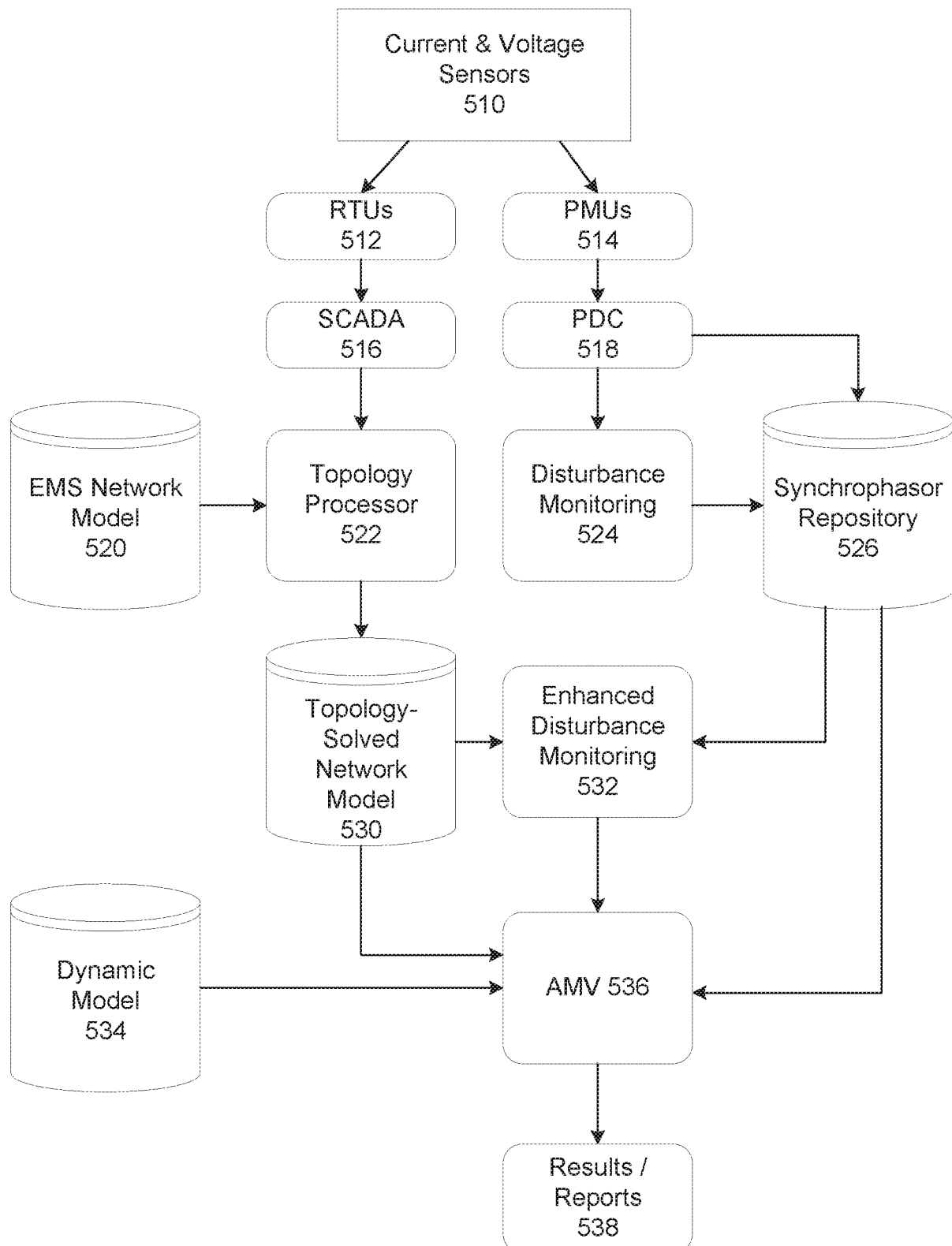
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FIG. 6

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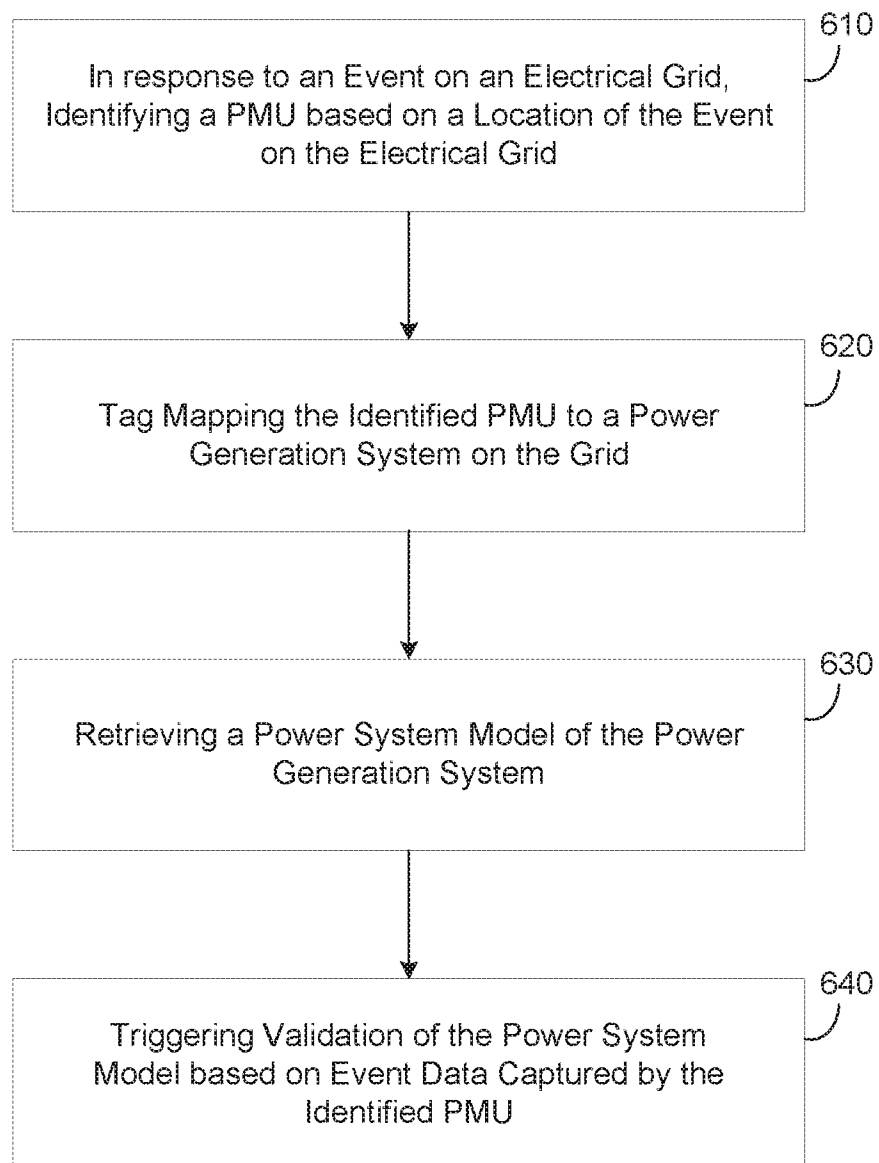
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FIG. 7

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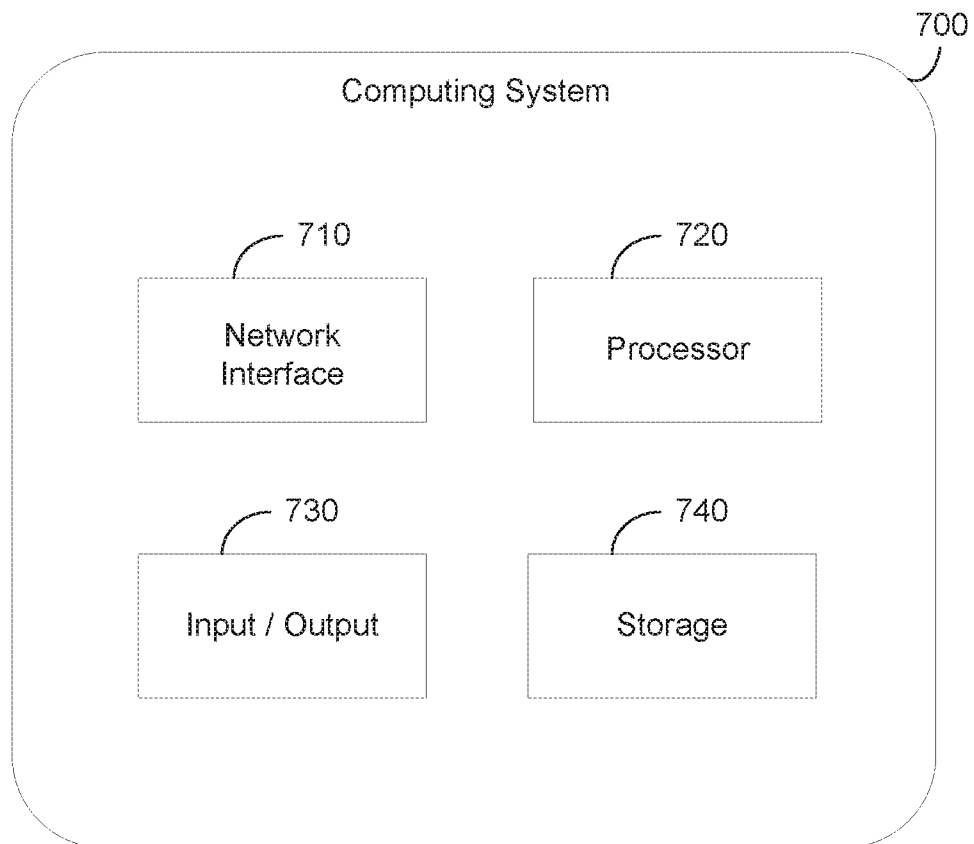
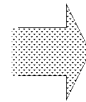


FIG. 8A

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EMS Info 802			POI PMU Info 804				General Info 806	
Sta. Name	Type	Device	PMU ID	PMU Name	PMU V. Phas	PMU C. Phas	Generator	Station
W. Shore	Gen	ABCD	12280	Electric Rd	G345	G345	Elec. Rd. U3	Elec Rd
W. Shore	Gen	EFGH	12280	Electric Rd	G345	G345	Elec. Rd. U2	Elec Rd
Elec Rd	Gen	ERD1	12280	Electric Rd	G345	G345	EFGH	W Shore
Elec Rd	Gen	ERD2	12260	Westshor A	B115	B115	Elec. Rd. U1	Elec Rd
Elec Rd	Gen	ERD3	12260	WestshorA	B115	B115	ABCD	W Shore



808

EMS Info			POI PMU Info				General Info	
Sta. Name	Type	Device	PMU ID	PMU Name	PMU V. Phas	PMU C. Phas	Generator	Station
W. Shore	Gen	ABCD	12260	Westshor A	B115	B115	ABCD	W Shore
W. Shore	Gen	EFGH	12260	WestshorA	B115	B115	EFGH	W Shore
Elec Rd	Gen	ERD1	12280	Electric Rd	G345	G345	Elec. Rd. U1	Elec Rd
Elec Rd	Gen	ERD2	12280	Electric Rd	G345	G345	Elec. Rd. U2	Elec Rd
Elec Rd	Gen	ERD3	12280	Electric Rd	G345	G345	Elec. Rd. U3	Elec Rd

FIG. 8B

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850

POWER SYSTEM MODEL

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POWER SYSTEM AUTO MODEL VALIDATION SYSTEM

Dist. Monitor

PMU Selection

Tag Mapping

File Collection

Subsystem

VALIDATION

IDENTIFIABILITY

CALIBRATION

200

Grid

POI PMU Information		
PMU ID	PMU Name	PMU C. Phasor
220A	West Sh. A	Genbus VS ABCD IS
220B	West Sh. B	Genbus VS ABCD IS
220C	West Sh. C	Genbus VS ABCD IS
220D	Elec. Rd. A	G345 UI VP G345 IP
220E	Elec. Rd. B	G345 UI VP G345 IP

FIG. 9

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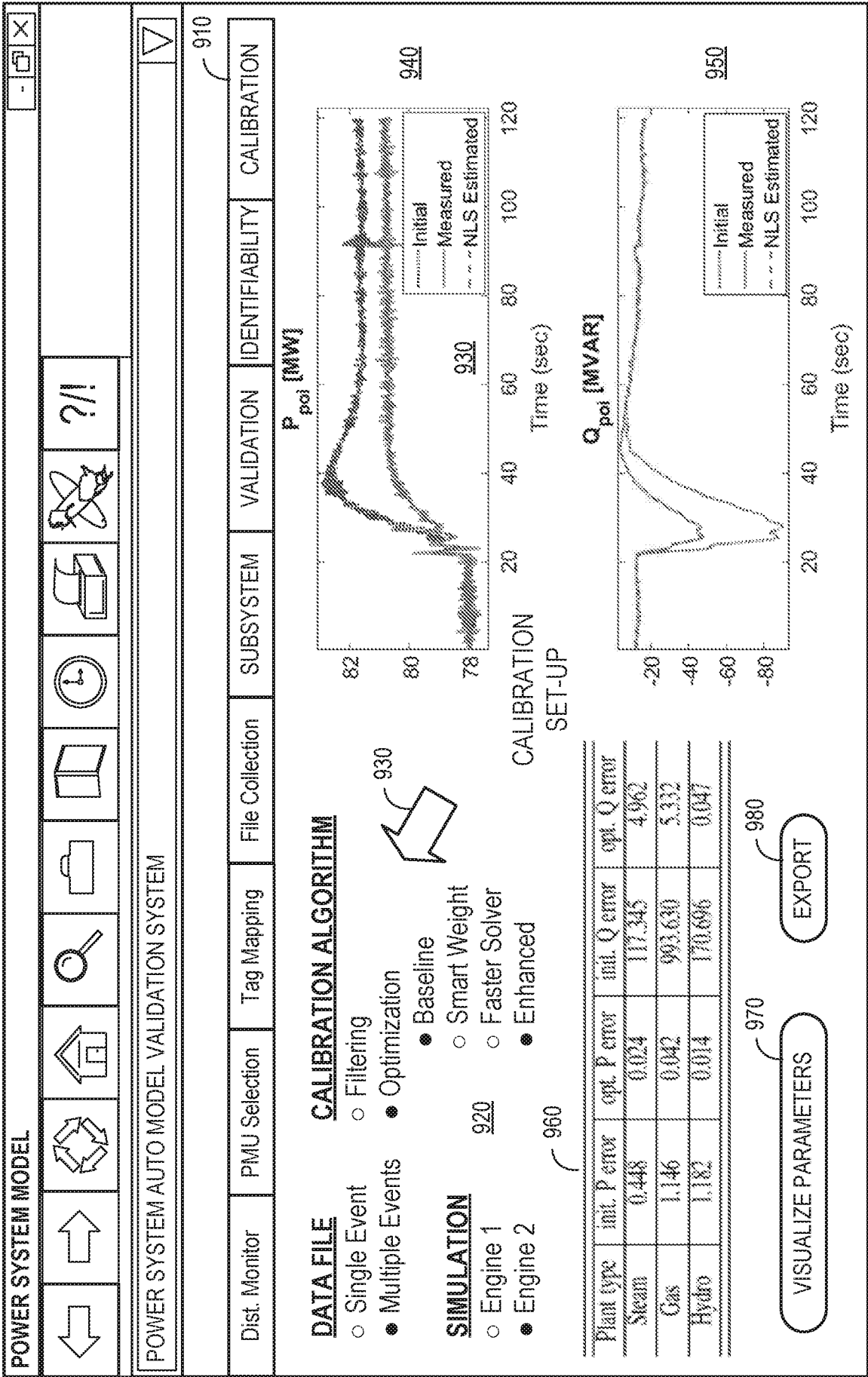
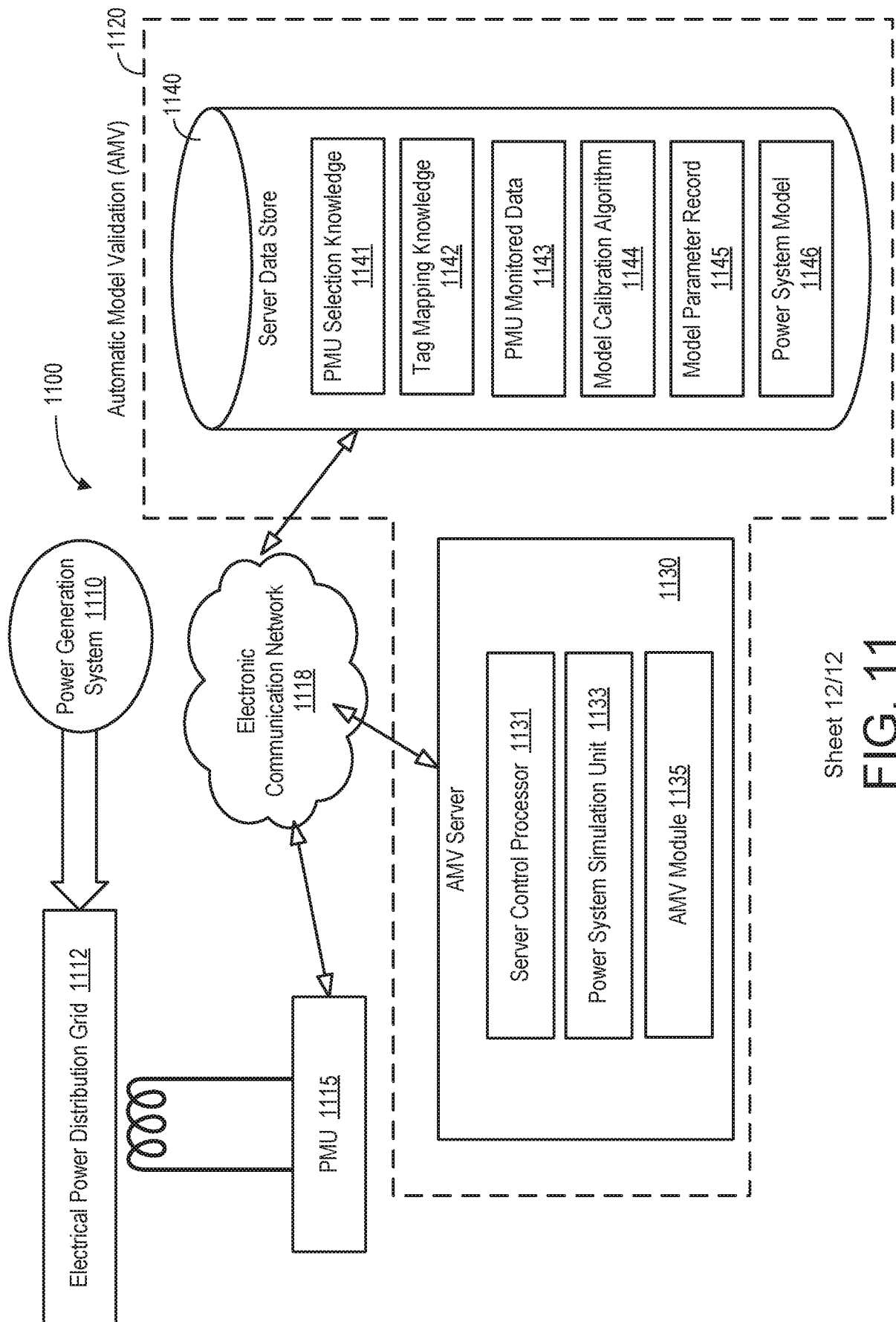


FIG. 10

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1002	1004	1006	1008	1010	1012	1014	1016	1018	1020	1022	1024
Event ID	Event Type	PMU Location STIKV/ND	PMU ID	DIF	PMU Selection	Mapped Generator	Network Model File	Dynamic Model File	PMU Event File	Model Validation	Model Calibration
12012	Unit trip	CANADA8 500KV Node 123	BRN-7_10_1	100%	Yes	ABCD	CIM1	ABCD.dyd			
12013	Unit trip	WASHING3 500KV Node 128	BRN- 10_82_1	64.70%	Yes	EFGH	CIM2	EFGH.dyd			
12014	Line out	OREGON8 500KV Node 128	BRN- 89_122_1	31.60%	Yes	AA22	CIM3	AA22.dyd			
12015	Line in	CANADA1 500KV Node 128	BRN-2_80_1	25.80%	No						



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FIG. 11

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2019/017008

A. CLASSIFICATION OF SUBJECT MATTER
INV. H02J3/00 H02J13/00
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
H02J

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 9 362 746 B2 (SHAFFER SHMUEL [US]; ZHA JUN [US]; CISCO TECH INC [US]) 7 June 2016 (2016-06-07) the whole document	1-20
A	US 2018/095123 A1 (BISWAS SAUGATA SWAPAN [US] ET AL) 5 April 2018 (2018-04-05) the whole document	1-20
A	EP 3 301 774 A1 (GENERAL ELECTRIC TECHNOLOGY GMBH [CH]) 4 April 2018 (2018-04-04) the whole document	1-20
A	WO 2012/035433 A2 (NEXANS [FR]; AIVALOITIS SARANTOS K [US] ET AL.) 22 March 2012 (2012-03-22) the whole document	1-20
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Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

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"P" document published prior to the international filing date but later than the priority date claimed

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"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

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"&" document member of the same patent family

Date of the actual completion of the international search

24 April 2019

Date of mailing of the international search report

09/05/2019

Name and mailing address of the ISA/

European Patent Office, P.B. 5818 Patentlaan 2
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INTERNATIONAL SEARCH REPORT

International application No
PCT/US2019/017008

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WO 2013/158813 A1 (ABB RESEARCH LTD [CH]; STOUPIS JAMES [US]; WANG ZHENYUAN [US]) 24 October 2013 (2013-10-24) the whole document	1-20
A	----- US 2014/244065 A1 (BISWAS SAUGATA SWAPAN [US] ET AL) 28 August 2014 (2014-08-28) the whole document -----	1-20

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No

PCT/US2019/017008

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