SmartConnect Use Case:

D13 – Power system automatically triggers FACTS devices using phasor data to maintain system stability

April 15, 2009

Documet History

Revision History

Revision Number	Revision Date	Revised / Reviewed By	Summary of Changes	Changes marked
(#)	(yymmdd)	(Name)	(Describe change)	(Y/N)
0.1	081123	Kevin Clampitt	Initial draft from workshop on November 3, 2008	N
0.2	090410	Kevin Clampitt	Second draft	N

Approvals

This document requires following approvals.

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Contents

1. Use Case Description

1.1 Use Case Title

Power system automatically triggers FACTS devices using phasor data to maintain system stability.

1.2 Use Case Summary

This use case describes how the coordinated use of phasor measurement data and FACTS devices could enable SCE to maintain system stability following a destabilizing event such as the loss of a transmission line or substation transformer. SCE currently uses phasor data to evaluate system conditions on a post-mortem basis, following such events. This use case describes the use of phasor data to control FACTS devices to restore system stability within 10 seconds of an event. This capability would reduce the likelihood of an event causing widespread catastrophic grid instability. Phasor data measures the physical characteristics of voltage and current waveforms, including phase angle and frequency oscillation. If frequency oscillation is identified, SCE's Predictive Grid Control System would calculate an optimal oscillation damping strategy, and send control messages to FACTS devices to execute the damping strategy. This use of phasor data to control FACTS devices represents one method within a portfolio of tools to combat system instability, and should be considered within a broader context of intelligent grid control. Other methods include Centralized Remedial Action Schemes (discussed in use case D15), and tools that optimize for other system variables such as transmission loss, volt/VAR control, generation dispatch, and renewable resource penetration levels. The benefits of this process include improved system reliability, reduced costs and increased customer benefits.

1.3 Use Case Detailed Narrative

Recent years have witnessed an increasing number of "reliability events" in major cities, and in entire geographic regions, demonstrating the vulnerability of electricity transmission systems to widespread and prolonged outages. The 2003 Eastern Interconnection blackout that affected the northeastern U.S. and parts of Canada, and the 2006 blackouts in Europe are two recent examples. There is general agreement that deregulation, growing electricity demand, and a changing mix of generation resources are placing the electricity grid under increased stress, contributing to the rise in reliability events.

In California, one source of system stress relates to deregulation of the wholesale electricity market. Prior to deregulation in 1997, SCE planned, built and operated generation, transmission and distribution infrastructure in an integrated manner. Service reliability was one objective of this integrated framework, causing SCE to construct a network of transmission lines for use during outages and periods of instability. For example, during transmission line outages, backup lines would allow SCE to maintain service. Following deregulation, Independent Power Producers (IPP) are able to locate generation resources in areas without backup transmission. SCE provides interconnection of these new resources to its transmission system, and the IPPs pay for this service. IPPs may opt to pay for redundant transmission, or they can allow the generation to "trip" during transmission outages. This form of tripping is performed through Centralized Remedial Action Schemes (discussed in use case D15). Due to the high cost of transmission capacity most IPPs opt to allow generation curtailment rather than build the transmission redundancy. Available transmission capacity has not kept pace with needed transmission capacity for additional reasons, including growth in electricity demand, a "not in my backyard" political environment which delays construction approvals, and the need to connect remote renewable resources. These factors are causing the grid to operate in a manner different than was intended during its construction. This results in system stress, which will increasingly threaten grid stability unless efforts are made to mitigate it.

This use case discusses the coordinated use of phasor data and FACTS devices as a means of maintaining system stability following a destabilizing event. This represents one among a number of tools to combat system instability, and should be considered within the broader context of an intelligent grid control system. Related tools include Centralized Remedial Action Schemes (C-RAS), and applications, systems and devices that optimize different system variables such as transmission losses, volt/VAR control, generation dispatch, and renewable resource penetration levels.

The triggering event in this use case scenario involves a large system disturbance, a 3-phase fault, which results in the loss of a transmission line and a generation facility. This is just one example of many possible triggers that could be used to demonstrate the potential coordinated use of phasor measurement data and FACTS devices. Phasor measurement data and FACTS devices would be used to maintain system stability during the initial 10 seconds following the destabilizing event. Over the longer term (e.g. after several seconds), other generation would be brought on line to replace the deficiency. For example, after several seconds Automatic Generation Control (AGC) would begin supplying limited amounts of balancing energy. After approximately 10 minutes, ancillary services and power procured in the real-time market would replace the AGC. However, during the initial 10 seconds, phasor measurement data and FACTS devices would be used to damp the oscillations, maintaining system stability prior to these other sources of generation being brought online.

Following the 3-phase fault, multiple Phasor Measurement Units (PMU) would capture a series of phasor data. The phasor data would include phase angle measurements, system frequency, as well as the system electrical parameters. The PMUs would then transmit this phasor data to Phasor Data Concentrators (PDC), devices that aggregate phasor data from multiple PMUs. There would be multiple PDCs throughout SCE's service territory. The PDCs would then transmit the phasor data to the Predictive Grid Control System (PGCS). The relay of this information from the PMU to the PGCS would occur in real-time, within 2 cycles of measurement. PGCS is a hypothetical application that would use phasor data to calculate a series of severity metrics which determine the system's state and whether stability control is needed. The analysis would include an examination of frequency oscillations, in terms of both their absolute value and rate of change. PGCS would also identify changes in phase angle differences. Growth in phase angle differences following the system event would increase the likelihood of PGCS deciding to damp the oscillations.

Once PGCS determines system stability control is required, it would alert the EMS Operator via the EMS dashboard that it is armed and ready to take action. PGCS would then calculate an optimal strategy to damp the system oscillations. PGCS would determine this strategy by performing a second set of algorithms and by assessing the state of the available FACTS devices. The algorithms would take into account the current state of the grid (e.g. which breakers are open, information about the fault, etc.), based on topological data provided by SCADA and other systems. Any viable mitigation strategy should "first do no harm", and must not simply transfer the problem to a different grid area. Thus, the PGCS strategy may be to do nothing. In most cases, however, we expect PGCS would calculate a strategy capable of damping the oscillations.

Based on the optimal strategy, PGCS would send control messages to the appropriate FACTS devices, instructing them to enter a particular mode. FACTS devices typically have 2 or 3 modes. For example, static VAR compensators (SVC) have a "voltage/VAR control" mode and a "power system stabilizer" mode. PGCS would control FACTS devices by setting the mode of operation and the required set points for that mode. Due to the diversity of devices and communications requirements for these devices, it is probably unfeasible to control them via millisecond by millisecond control commands. PGCS would notify the EMS Operator of the control action via the EMS dashboard. The FACTS devices would acknowledge receipt of the commands, implement the commanded action, and continue providing status feedback to PGCS until the stability event is over. Once the oscillations have been damped, PGCS would command the FACTS devices to return to the normal steady state mode of operation.

Using phasor measurement data to indirectly control FACTS devices (via the PGCS) is among the most challenging of the next generation of real-time grid management applications. It requires high speed data collection, rapid calculation, and a sophisticated level of intelligence and communication requirements to control the FACTS devices. The speeds required to control field devices in this manner suggest the possibility of a move from traditional "state estimation" with a limited number of sensors, to "state measurement" with a greater number of PMU sensors (perhaps at nearly every critical node). The electric utility industry has discussed these measurement and control concepts for several years. However, only recently have the phasor measurement technologies been available, and only recently have communications technologies been both inexpensive and fast enough to enable it.

Business Value

The benefits of using phasor data to automatically trigger FACTS devices to maintain system stability include the following:

1. **Improved System Reliability**:
   a. Avoid Service Interruptions: Improved power quality and system reliability would result in avoided service interruptions. Service interruptions and blackouts have large societal costs, including losses in productivity, and risks to public health and safety.
   b. Customer Satisfaction: Increased reliability would result in increased customer satisfaction.
   c. Penalty Reduction: If out of compliance with WECC & NERC reliability requirements, a utility may be charged $1 million per occurrence per day. These penalties can be charged retroactively.
2. **Reduced Costs**:
   a. Reduce Dependence on Remedial Action Schemes: SCE might be able to reduce its dependence on severe remedial action schemes by implementing a finer level of grid control. Designing, testing and maintaining remedial action schemes can be expensive, so any reduction in dependence on these programs would reduce operations expense.
   b. Improve Capacity Utilization: An improvement in its ability to restore stability during an event would allow SCE to increase transmission capacity utilization. It would operate with a reduced risk of system failure.
   c. Keep Economically Viable Generation Online: SCE would be able to keep economically viable generation online and avoid tripping due to system instability if it is better able to monitor and maintain stability with FACTS devices.
   d. Congestion Management: SCE's ability to maintain system stability will allow it to better manage congestion by increasing transmission throughput with a reduced risk of system failure.

e. Import Nomogram Improvement: If SCE is able to respond more quickly to maintain stability during an event, it might be able to increase the level of imported generation allowed by the import nomogram. This would allow SCE to economize its energy procurement by replacing some amount of higher cost local generation with lower cost imported generation. Use of FACTS devices would allow SCE to maintain stability as it reduces local generation and brings in imported generation.

f. Reduce Operating Costs: PGCS' monitoring and control capabilities would allow SCE to operate the transmission system more efficiently, resulting in a reduction to operating expenses.

g. Capital Efficiency Improvement: Avoiding catastrophic grid events will extend the useful lives of SCE's capital equipment.

3. **Increased Customer Benefits**:

a. Avoid Collateral Damage: A reduction in catastrophic failures reduces potential collateral damage. Collateral damage includes customer interruption and economic loss, declines in customer satisfaction, loss of capital assets, loss of revenue, and loss of productivity during service restoration periods.

1.4 Business Rules and Assumptions

- The geographic scope includes the WECC area.
- Other system actions are occurring to restore load generation balance. For example, after loss of generation the ISO would first use Automatic Generation Control (AGC) to provide small amounts of regulation power. The ISO might then use other ancillary services such as spinning or non-spinning reserves. After several minutes the ISO could direct SCE to import power from other sources, re-dispatch other generators, etc., to restore balance.
- The PGCS mitigation process begins after the fault clears.

2. Actors

Describe the primary and secondary actors involved in the use case. This might include all the people (their job), systems, databases, organizations, and devices involved in or affected by the Function (e.g. operators, system administrators, customer, end users, service personnel, executives, meter, real-time database, ISO, power system). Actors listed for this use case should be copied from the global actors list to ensure consistency across all use cases.

Actor Name	Actor Type (person, device, system etc.)	Actor Description
Flexible AC Transmission System Device (FACTS device)	Device	FACTS devices are a family of control devices characterized by solid state switching, fast action (within 2 cycles), and customized controls. Different devices have different modes of operation to perform different tasks. Static VAR compensators are one type of FACTS device that provide voltage support. Other FACTS devices assist with power flow control and phase shifting.
Phasor Data Concentrator (PDC)	Device	This is a device that collects and aggregates phasor data from multiple Phasor Measurement Units (PMU) and relays the data to the Predictive Grid Control System. There would be multiple PDCs throughout SCE's service territory.
Phasor Measurement Unit (PMU)	Device	Phasor Measurement Units (PMU) are devices capable of measuring voltage and current sinusoidal waveforms on transmission lines, and transmitting the data to the utility for monitoring and control purposes. The data consists of phase angles, frequency, and electrical parameters (voltage, current, real power and reactive power). The data is accurately time-stamped to IEEE standards, and is capable of being transmitted to the Predictive Grid Control System within 100 milliseconds.
Predictive Grid Control System (PGCS)	System	The PGCS is a system that receives data from Phasor Measurement Units (PMU) and other sensor devices, determines that stability control is needed, calculates the optimal strategy, and communicates that strategy to FACTS devices. PGCS is a hypothetical future system that can perform this function. This system is currently undefined. It could be a next generation Energy Management System. Likewise, it may be either centralized or distributed. The system architecture will be determined after a more detailed analysis of the system requirements.

3. Step by Step analysis of each Scenario

Describe steps that implement the scenario. The first scenario should be classified as either a "Primary" Scenario or an "Alternate" Scenario by starting the title of the scenario with either the work "Primary" or "Alternate". A scenario that successfully completes without exception or relying heavily on steps from another scenario should be classified as Primary; all other scenarios should be classified as "Alternate". If there is more than one scenario (set of steps) that is relevant, make a copy of the following section (all of 3.1, including 3.1.1 and tables) and fill out the additional scenarios.

3.1 Primary Scenario: Predictive Grid Control System maintains grid stability by engaging appropriate FACTS devices (e.g. SVCs) in response to grid abnormalities detected by the phasor monitoring system

This scenario describes how SCE would respond to a 3-phase line fault that results in a line and generator trip. Following this system event, Phasor Measurement Units (PMU) would capture a series of phasor measurement data and transmit it to SCE's Predictive Grid Control System (PGCS) via Phasor Data Concentrators (PDC). The data would be transmitted to PGCS in real-time, within 2 cycles of measurement. PGCS would then analyze the data to determine the system state and whether power system stabilizing is required. This determination is based on whether there is growth in phase angle differences, as well as the size of any associated frequency oscillations. If system stability is required PGCS would then calculate an optimal strategy for damping the oscillations. The optimal strategy would consist of a FACTS device entering a specific "stability mode" of operation. PGCS would then send control messages to appropriate FACTS devices to implement the optimal oscillation damping strategy. The FACTS devices would acknowledge receipt of the message and implement the control action. PGCS would continue sending a subset of PMU data to the FACTS device to enable it to operate more optimally. Once PGCS determines the stability event is over it would instruct the FACTS device to return to its normal mode of operation.

Triggering Event	***Primary Actor***	***Pre-Condition***	***Post-Condition***
(Identify the name of the event that start the scenario)	*(Identify the actor whose point-of-view is primarily used to describe the steps)*	*(Identify any pre-conditions or actor states necessary for the scenario to start)*	*(Identify the post-conditions or significant results required to consider the scenario complete)*
3-phase fault on line causes line and generation trip.	Predictive Grid Control System (PGCS)	FACTS devices are operating in the steady state mode, optimizing for voltage control in the corridor.	The oscillations have been damped and the FACTS device is returned to the steady state mode.

3.1.1 Steps for this scenario

Describe the normal sequence of events that is required to complete the scenario.

Step #	Actor	Description of the Step	Additional Notes
#	*What actor, either primary or secondary is responsible for the activity in this step?*	*Describe the actions that take place in this step. The step should be described in active, present tense.*	*Elaborate on any additional description or value of the step to help support the descriptions. Short notes on architecture challenges, etc. may also be noted in this column.*
1	Phasor Measurement Unit (PMU)	Phasor Measurement Unit measures phasor data.	The PMU data shall include phase angle measurements, frequency, voltage, current, and other state information. The PMU data shall be accurately time-stamped to IEEE standards.
2	PMU	PMU transmits phasor data to Phasor Data Concentrator (PDC).	SCE would have multiple PDCs in its service territory, each of which would receive phasor data from multiple PMUs. PMU data would be transmitted through a Phasor Data Network which facilitates communication between the individual Phasor Measurement Units, Phasor Data Concentrators and the Predictive Grid Control System.
3	PDC	PDCs send phasor data to the Predictive Grid Control System (PGCS).	This use case does not prescribe a system architecture for PGCS. PGCS may consist of one centralized application that collects all phasor data at one location, or it may consist of multiple regional applications that collect a subset of phasor data. The final architecture will be driven by the number

Step #	Actor	Description of the Step	Additional Notes
			of PMUs, communications, latency and data payload requirements, in addition to economic considerations.
4	PGCS	PGCS calculates a series of severity metrics to determine the system state.	PGCS examines the PMU data and calculates a series of real-time severity metrics to determine the state of the system. This analysis includes an examination of frequency oscillations, and the rate of change of these oscillations. PGCS also identifies changes in phase angle differences. Phase angle differences exist between various locations on an interconnected system. Phase angle differences are normally 30 to 40 degrees across the WECC system. Generally speaking, the greater the phase angle difference, the greater the amount of power transfer. As phase angle differences increase, however, the grid becomes less tolerant of system disturbances. Phase angle differences exceeding 90 degrees can lead to loss of synchronism (e.g. regional system separation), which could result in blackout conditions. Consequently, if there is growth in the phase angle difference following a system disturbance, this will influence the decision to damp any associated frequency oscillations.
5	PGCS	PGCS determines that stability control mode is required.	PGCS determines that stability control mode is required based on the algorithms and severity metrics calculated in step 4. PGCS shall damp frequency oscillations within a range of 0.2 to 1.0 Hz.

Step #	Actor	Description of the Step	Additional Notes
			PGCS would wait for the fault to clear before taking action in order to avoid damaging the FACTS device. In addition, during a fault the voltage is too low for FACTS devices to operate properly. Once PGCS determines stability control mode is required, it notifies the EMS Operator via the EMS dashboard that it is armed and ready to take action. PGCS would also make this information available to the Independent Systems Operator (ISO).
6	PGCS	PGCS calculates an optimal strategy for damping system oscillations.	PGCS determines an optimal course of action to damp system oscillations by running a series of algorithms and assessing the states of the available FACTS devices. The algorithms would take into account the current state of the grid (which breakers are open, information about the fault, etc), based on topological information provided by SCADA and other systems. PGCS would be aware of the FACTS device states as these devices communicate their modes of operation to PGCS whenever they change. The optimal strategy may be to do nothing if PGCS is unable to generate a viable mitigation strategy. Viable mitigation strategies must not transfer the problem to other grid areas. Once PGCS calculates the optimal strategy, it notifies the EMS Operator via the EMS dashboard. PGCS would also

Step #	Actor	Description of the Step	Additional Notes
			make this information available to the ISO.
7	PGCS	PGCS sends control messages to appropriate FACTS devices.	Based on the optimal strategy, control messages are sent to the appropriate FACTS devices, instructing them to enter a particular mode. FACTS devices typically have 2 or 3 modes. For example, static VAR compensators (SVC) have a "voltage/VAR control" mode and a "power system stabilizer" mode. PGCS would control FACTS devices by setting the mode of operation and the required set points for that mode. Due to the diversity of devices and communications requirements for these devices, it is probably unfeasible to control them via millisecond by millisecond commands. In addition to commanding the FACTS devices to enter a particular mode, PGCS would send initial set point information to control how the oscillation damping is accomplished. If the FACTS device is an SVC, PGCS would also need to activate capacitor controls on other capacitors. Switching an SVC from voltage/VAR control mode to power system stabilizer mode would temporarily remove the SVC's VAR support, and other capacitors would need to compensate for this loss of support. PGCS would notify the EMS Operator via the EMS dashboard. PGCS would also make this information available to

Step #	Actor	Description of the Step	Additional Notes
			the ISO.
7.1	PGCS	PGCS continues sending PMU data to FACTS devices.	PGCS would also continue sending a subset of PMU data to the FACTS devices as long as they are operating in the system stability mode to assist them in operating more efficiently.
8	FACTS devices	FACTS devices acknowledge receipt of control command.	
9	FACTS devices	FACTS devices take commanded action.	The FACTS devices would take the system-stabilizing control actions based on the mode and set point control message sent from PGCS. These actions would be taken without any cycle-by-cycle control commands from PGCS. PGCS would notify the EMS Operator of all current status information via the EMS dashboard. PGCS would also make this information available to the ISO.
10	FACTS devices	FACTS devices provide ongoing status feedback to PGCS.	
11	PGCS	PGCS determines that stability event is over.	Based on current PMU data, PGCS determines the oscillation has been damped. PGCS would notify the EMS Operator, and make the information available to the ISO.
11.1	EMS Operator	If PGCS is unable to restore stability, the EMS Operator performs other control actions to restore stability.	If the PGCS is unable to adequately damp the oscillation, the EMS Operator would take other steps to mitigate the oscillations. This would likely involve coordination with the ISO to re-dispatch the generator or import power from other sources. This could also involve reconfiguring the system by controlling

Step #	Actor	Description of the Step	Additional Notes
			switches to route line flow around the problem area.
12	PGCS	PGCS commands FACTS device to return to its normal mode of operation.	PGCS would notify the EMS Operator, and make the information available to the ISO.
13	FACTS devices	FACTS devices acknowledge receipt of control command.	
14	FACTS devices	FACTS devices take commanded action and return to normal mode of operation.	

4. Requirements

Detail the Functional, Non-functional and Business Requirements generated from the workshop in the tables below. If applicable list the associated use case scenario and step.

4.1 Functional Requirements

Req. ID	*Functional Requirements*	*Associated Scenario #* (if applicable)	*Associated Step #* (if applicable)
1	Phasor Measurement Units (PMUs) shall measure phasor angles.	1	1
2	PMUs shall measure voltage frequency.	1	1
3	PMUs shall measure voltage.	1	1
4	PMUs shall measure current.	1	1
5	PMUs shall measure real power.	1	1
6	PMUs shall measure reactive power.	1	1
7	All data required by PGCS shall be accurately time-stamped.	1	1, 8 & 10
8	PMU shall send phasor data to Phasor Data Concentrators (PDCs).	1	2
9	PDCs shall send phasor data to PGCS	1	3
10	The Predictive Grid Control System (PGCS) shall receive phasor data from PDCs and other sensors.	1	3
11	PGCS shall calculate a series of severity metrics to determine the state of the system.	1	4
12	PGCS shall evaluate system oscillations.	1	4
13	PGCS shall evaluate the rate of change of system oscillations.	1	4
14	PGCS shall calculate changes in phase angle differences.	1	4
15	PGCS shall filter out non-critical or stable data (i.e. eliminates false positives).	1	4

Req. ID	Functional Requirements	Associated Scenario # (if applicable)	Associated Step # (if applicable)
16	PGCS shall wait for fault to clear before taking action.	1	5
17	PGCS shall detect that the fault has cleared based on voltage magnitude.	1	5
18	PGCS shall alert the EMS Operator that it has activated and is ready to take action to restore system stability. This notification shall delivered to the EMS dashboard	1	5
19	PGCS shall provide visibility of its operational status and course of action to EMS Operator via the EMS dashboard.	1	5, 6, 7, 9, 11 & 12
20	PGCS shall provide visibility of its operational status and course of action to the Independent System Operator (ISO). ISO will likely want to know what PGCS is doing since its actions affect system stability and reliability.	1	5, 6, 7, 9, 11 & 12
21	EMS Operators shall be able to override PGCS. For example, if the EMS Operator knows that PGCS is about to take action and that the actions are incorrect, or if they know certain equipment is malfunctioning, the EMS Operator could inhibit or terminate the action.	1	5, 6, 7 & 9
22	PGCS shall calculate an optimal strategy for damping system oscillations.	1	6
23	PGCS system oscillation damping strategies shall not transfer problems to other grid areas.	1	6
24	PGCS shall have an internal topological model of the grid.	1	6
25	The PGCS topological model of the grid shall indicate the current state (e.g. which breakers are open, and information about the fault, including whether it is a normal clearing fault, a delayed-clearing fault or 3-phase fault). PGCS shall obtain this information from the PMU raw data and other systems. It is necessary for the PGCS to know the current state so it can calculate an optimal strategy to damp the system oscillation.	1	6
26	PGCS shall be configured to adapt to topology changes.	1	6
27	PGCS shall be configured to adapt to behaviors of past events.	1	6
28	PGCS shall integrate with the Centralized Grid Capacitor Control (CGCC) to prevent a conflict between their efforts. They both can be used for voltage/VAR control, and thus their activity needs to be coordinated.	1	7

Req. ID	*Functional Requirements*	*Associated Scenario #* *(if applicable)*	*Associated Step #* *(if applicable)*
29	FACTS devices shall provide status information to PGCS. This would include the control mode and other real-time device information which will vary by device (and by how much local intelligence the device has). This information assists PGCS in calculating an optimal damping strategy, and in verifying that the control command was actually implemented by the FACTS device.	1	6, 8 & 10
30	PGCS shall send operating mode commands to FACTS devices.	1	7 & 12
31	PGCS shall log actions taken (to serve as an audit trail).	1	7
32	If the FACTS device is an SVC, PGCS shall activate capacitor controls on other capacitors. Switching an SVC from voltage/VAR control mode to power system stabilizer mode would temporarily remove the SVC's VAR support, and other capacitors would need to compensate for this loss of support.	1	7
33	PGCS shall stream a subset of PMU data to FACTS devices. This data is streamed to the FACTS device for as long as the FACTS device operates in the power system stability mode.	1	7.1
34	PGCS shall use a standardized protocol to communicate with FACTS devices. There is a large number of FACTS devices with different manufacturers and standards of communication. For the purposes of SCE's system, there needs to be uniformity in the messaging between all these devices and PGCS. This use case will not prescribe which standard, only that one is used.	1	7, 8, 10, & 12
35	FACTS devices shall acknowledge receipt of PGCS commands.	1	8 & 13
36	PGCS shall know when the oscillations have been damped.	1	11
37	PGCS shall have centralized management. The actual system architecture may include distributed control, where zone-based PGCSs send commands to devices within their respective zones, or alternatively a centralized PGCS sends mode-based controls to devices that possess intelligence to perform local optimization. Irrespective of the PGCS architecture hierarchy, PGCS and its algorithms shall be managed centrally.	1	All
38	PGCS shall integrate with basic protection schemes.	1	All
39	PGCS shall integrate with Centralized Remedial Action Schemes (C-RAS).	1	All
40	PGCS shall integrate with AGC functions (which are under control of the ISO).	1	All

4.2 Non-functional Requirements

Req. ID	*Non-Functional Requirements*	*Associated Scenario #* *(if applicable)*	*Associated Step #* *(if applicable)*
1	PMUs shall provide 30 data points per second (1 data point for every other cycle).	1	1
2	PMU time-stamping of data shall comply with IEEE time-stamping standards.	1	1
3	Phasor Data Concentrator (PDC) messages to PGCS shall comply with IEEE standard C37.118.	1	3
4	PGCS shall receive PMU data within 100 milliseconds.	1	3
5	PGCS shall process data from an appropriate number of PMUs for each event. On average this will be 6-8 PMUs, with a maximum of 20 PMUs. This shall be driven by the system location and type of problem. WECC events would likely require 20 PMUs, whereas a Big Creek event would require fewer than 6 PMUs.	1	4
6	PGCS shall perform calculations within 2 cycles (coinciding with retrieval of the next data point). This is necessary to track the oscillation trends as they occur.	1	4, 5 & 6
7	PGCS shall damp oscillations with a range of 0.2 Hz to 1.0 Hz (the range of observed WECC power system frequency oscillations).	1	5
8	There shall be a sufficient number of PMUs to provide redundancy and ensure confidence in the data the PGCS uses to calculate mitigation strategies. Since this involves state measurement, SCE needs more monitoring points than would be required for state estimation. This is intended to avoid PGCS prescribing suboptimal strategies, potentially exacerbating the situation rather than improving it.	1	6
9	PMU messages to PGCS shall comply with IEEE standard C37.118.	1	6, 8 & 10
10	PGCS control commands to FACTS devices have latency requirements no greater than 100 milliseconds.	1	7 & 12
11	PGCS shall stream a subset of PMU data to FACTS devices for as long as the FACTS device operates in the power system stability mode.	1	7.1
12	PGCS shall damp oscillations within 10 seconds of identification.	1	11

Req. ID	*Non-Functional Requirements*	*Associated Scenario #* *(if applicable)*	*Associated Step #* *(if applicable)*
13	System shall meet WECC regulations for system performance.	1	All
14	Each of SCE's interconnections shall have a PMU.	1	All
15	Each of SCE's key corridors shall have a PMU.	1	All
16	PGCS and other relevant phasor communications systems shall comply with NERC CIP standards.	1	All

5. Use Case Models (optional)

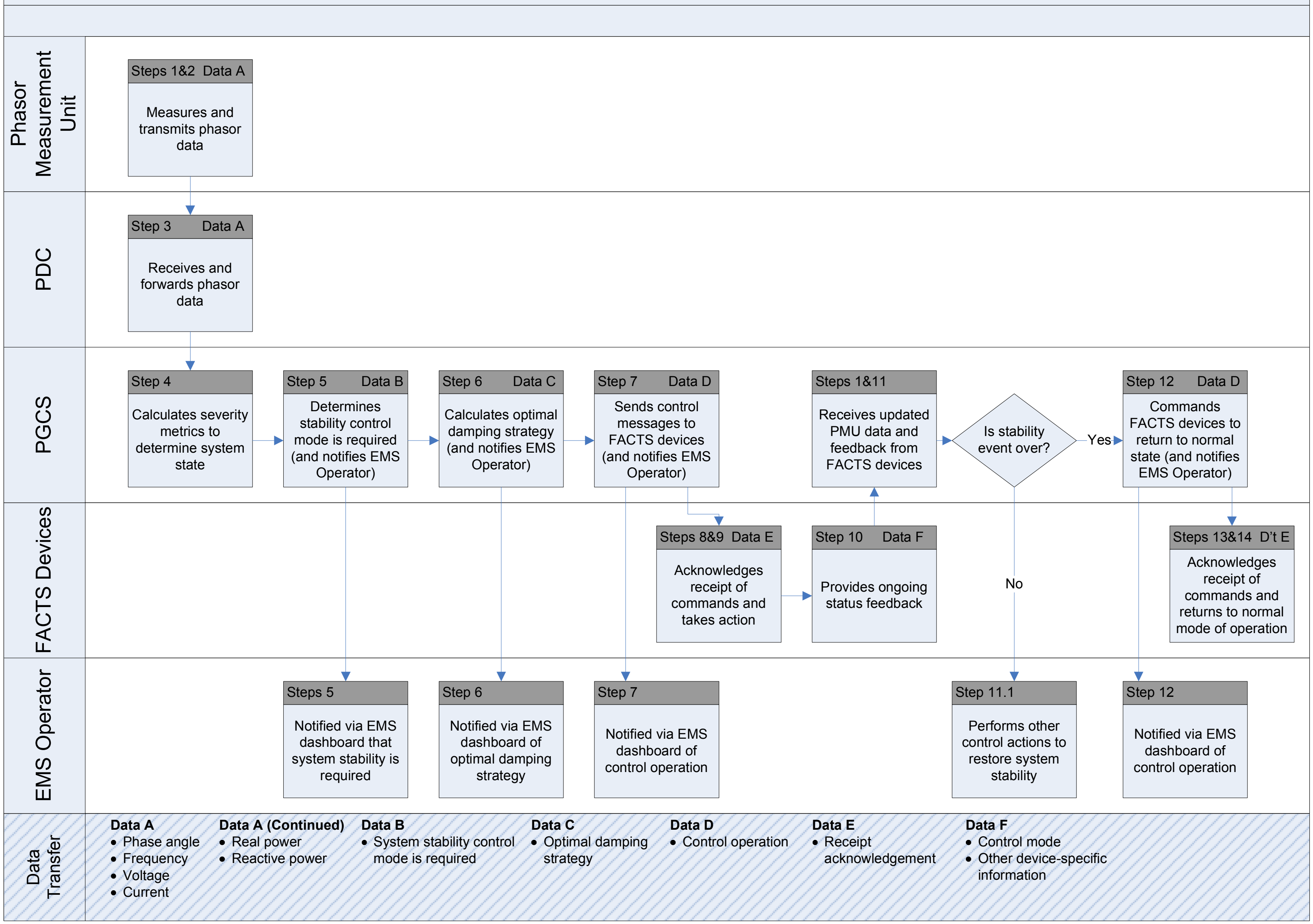
This section is used by the architecture team to detail information exchange, actor interactions and sequence diagrams

5.1 Information Exchange

For each scenario detail the information exchanged in each step

5.2 Diagrams

Use Case D13 – Scenario 1.1 Predictive Grid Control System maintains grid stability by engaging appropriate FACTS devices (e.g. SVCs) in response to grid abnormalities detected by the phasor monitoring system



6. Use Case Issues

Capture any issues with the use case. Specifically, these are issues that are not resolved and help the use case reader understand the constraints or unresolved factors that have an impact of the use case scenarios and their realization.

Issue
Describe the issue as well as any potential impacts to the use case.
1. How many sensors are needed to detect an event?
2. Implementation of the Predictive Grid Control System (PGCS) would require Operator training. The training would likely need to be NERC certified. The Operators need to understand what is happening, why it is happening, and whether the PGCS actions are appropriate. In association with this training, Operator simulators would need to be updated to be able to simulate the behaviors of PGCS algorithms.
3. Implementation of PGCS would require that planning tools be able to simulate PGCS behavior to assist with planning activities.

7. Glossary

Insert the terms and definitions relevant to this use case. Please ensure that any glossary item added to this list should be included in the global glossary to ensure consistency between use cases.

Glossary	
Term	**Definition**
Centralized Grid Capacitor Control (CGCC)	The Centralized Grid Capacitor Control is used to control bulk power capacitors through the EMS system. It is the application that allows SCE to coordinate the operation of capacitors (3,000MVar).
Energy Management System (EMS)	The Energy Management System is a system of tools used by system operators to monitor, control, and optimize the performance of the transmission system. The monitor and control functions are performed through the SCADA network. Optimization is performed through various EMS applications.
EMS Operator	The EMS Operator monitors the EMS systems. The Predictive Grid Control System (PGCS) alerts the EMS Operator when it determines that system stability control is required to damp oscillations. PGCS notifies the EMS Operator of its oscillation damping strategy as well as actions taken. The EMS Operator has the capability of overriding the PGCS.
Independent Power Producer (IPP)	Independent Power Producers are entities other than public utilities that own electric generation facilities that supply power to public utilities and other commercial and industrial customers.
Independent System Operator (ISO)	The Independent System Operator (ISO or Regional Transmission Organization) is responsible for the economic and reliable operation of the transmission grid. The ISO creates a functioning market for Energy, Capacity, and Ancillary Services. The ISO is responsible for compliance with federal and state rules and regulations.
North American Electric Reliability Corporation (NERC)	The North American Electric Reliability Corporation is a non-governmental organization that develops and enforces reliability standards for bulk power systems.
Phasor Data Network	The Phasor Data Network shall facilitate communications among the individual PMUs, PDCs and PGCS. It shall be capable of transmitting data in real time with minimal latency (2 cycles between event occurrence and delivery to PGCS).
SCADA (Supervisory Control and Data Acquisition)	SCADA refers a group of centralized systems that monitor and control the assets within SCE's transmission and distribution system. SCADA data is relayed in 4 second intervals.
State Estimator	The State Estimator performs an online process of estimating the current state of various points in the electrical system (power flows, voltages, etc). The estimation is performed using SCADA data. Since the SCADA system provides

	measurement data from various points in the system (but not all points), the State Estimator interpolates the state of the points between these SCADA-monitored points. The State Estimator identifies points that are out of specification, and alerts the system operator of potential problems.
Static VAR Compensator (SVC)	Static VAR Compensators are a type of FACTS device that helps to regulate voltage and reactive power (e.g. voltage/VAR control). These devices generally operate in one of two modes: (1) voltage/VAR control, or (2) power system stability.
System	This use case shall use the term "system" to refer to the broader electrical transmission system with the WECC area. System may also be used to refer to a specific SCE system. In these instances the name of the system will be specified.
Western Electricity Coordinating Council (WECC)	The Western Electricity Coordinating Council (WECC) is one of the eight regional reliability organizations of NERC. WECC is responsible for coordinating and promoting electric system reliability in its territory, which includes the 14 western US states, the Canadian provinces of Alberta and British Columbia, and northern Baja California, Mexico.

8. References

Reference any prior work (intellectual property of companies or individuals) used in the preparation of this use case

9. Bibliography (optional)

Provide a list of related reading, standards, etc. that the use case reader may find helpful.

1. 2009 SCE GRC Testimony of Centralized Remedial Action Scheme.