Voltage Control in Southwest Utah With the St. George Static Var System

Daniel Sullivan, *Member, IEEE*
John Paserba, *Fellow, IEEE*
Gregory Reed, *Member, IEEE*
Terry Croasdaile, *Member, IEEE*
Robert Westover, *Member, IEEE*
Ron Pape, *Member, IEEE*

Mitsubishi Electric Power Products, Inc.
Warrendale, Pennsylvania – USA

Masatoshi Takeda, *Member, IEEE*
Satoshi Yasuda, *Non-Member*
Hitoshi Teramoto, *Non-Member*
Yoshiyuki Kono, *Member, IEEE**
Ken-ichi Kuroda, *Non-Member**
Koji Temma, *Member, IEEE**

Mitsubishi Electric Corporation
Itami - Japan
*Kobe – Japan

William Hall, *Member, IEEE*
Duane Mahoney, *Non-Member*
Dean Miller, *Member, IEEE***
Paul Henry, *Non-Member*

PacifiCorp
Salt Lake City, Utah, - USA
**Portland, Oregon - USA

***Abstract*—PacifiCorp commissioned the St. George Static Var System (SVS) with a continuous rating of -35 to +100 Mvar (transient rating -70 to +278 Mvar) in June of 2006. This paper presents the Southwest Utah area transmission system, the requirements for voltage support, the planning and dynamic performance studies used in rating and verifying performance of the SVS, and provides an overview of the design and coordinated control strategy. An overview of the SVS stability model with integrated "smooth' and "stepped" susceptance control is also discussed.**

The St. George SVS is connected to the 138 kV bus of the St. George substation to enhance voltage control and dynamic Var support for major disturbances in the Southwest Utah 138 kV and 345 kV transmission systems. The SVS coordinated control strategy employs local and remote shunt reactive devices to reduce SVS reactive steady-state output and to regulate the voltage at the local St. George 138 kV bus and at the remote Red Butte 138/345 kV substation.

***Index Terms*—static Var system, SVS, static Var compensator, SVC, power system stability, voltage control, reactive power**

I. Introduction

St. George is located in the Southwest (SW) corner of Utah bordering Arizona and Nevada. As illustrated in Fig. 1, the St. George area is served from the major 345 kV transmission corridor between Sigurd, Utah and Las Vegas, Nevada.

Being served radially from this 345 kV transmission system leaves the St. George area vulnerable to inadequate voltage regulation and system dynamic performance problems for system disturbances on the 345 kV corridor or for disturbances on the 138 kV connection to the Red Butte substation. Inadequate voltage regulation for such network conditions is a known concern that can be solved by shunt compensation devices (static Var compensators, shunt capacitor/reactor banks) [1-3].

Planning studies show that as early as 2006, the St. George area requires additional voltage support to improve voltage regulation and prevent the possibility of voltage collapse following an outage of either of the 345 kV transmission lines into the Red Butte substation or an outage of one 138 kV transmission line between Red Butte/Central and St. George substations.

This paper gives details of a static Var system comprising a continuously rated -35 to +100 Mvar SVC and two integrally-controlled 89 Mvar (at 1.0 p.u. voltage) mechanically switched capacitors installed on the PacifiCorp system. The SVS also coordinates control of multiple shunt reactors and shunt capacitors both local and remote to the St. George substation. The SVS and coordinated controls effectively regulate the system voltage in the SW Utah area and provide adequate control of system dynamic performance following system disturbances.

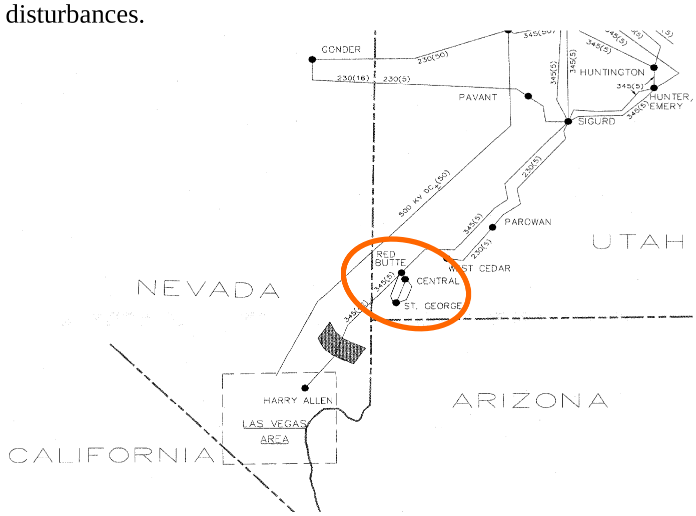

Fig. 1. Southwest Utah area transmission map.

II. Transmission System in Southwest (SW) Utah Area

The SW Utah area is shown in Fig. 1. This rapidly growing area is served from the Sigurd-Red Butte-Harry Allen 345 kV line at Red Butte, and from the radial 230 kV line from the Sigurd substation. The Sigurd-Red Butte-Harry Allen 345 kV line serves a dual purpose of importing/exporting power for the Utah area and serving the St. George area load. The Red Butte and Central 345/138 kV substations are adjoining substations. The Central and Red Butte 138 kV substations are connected to the St. George substation by three 21-mile long 138 kV lines.

Approximately 80 MW of local generation is located on the 138/69 kV transmission system served from the St. George substation. The amount of this generation that is on-line varies significantly.

By the summer of 2006, system additions include the St. George substation SVC, a 30 Mvar Red Butte substation 138 kV shunt capacitor bank, and a 30 Mvar St. George substation 138 kV shunt capacitor bank.

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Figure 2 is a simplified one-line diagram of the SW Utah system configuration in 2009. The Sigurd 345 kV and Harry Allen 230 kV buses are firm buses (significantly greater short circuit duty) with respect to the SW Utah system. The SW Utah loads served from the Red Butte 345 kV substation are normally served on radial 138 to 69/35 kV transmission systems beyond Red Butte and St. George substation. Major system changes from the 2006 system to 2009 system include the transfer of the Cedar City area load onto the Sigurd-Red Butte 345 kV line at a proposed Cedar Valley 345/138 kV substation and rebuilding the existing Red Butte-St. George 138 kV line to a double circuit 138 kV line. (The Cedar City area load will be served on a radial 230 kV line from the Sigurd substation until the Cedar Valley substation is added in 2008.) To maintain the Sigurd to Harry Allen 345 kV line transfer capability, a series capacitor bank (approximately 50% compensation) will be installed at Cedar Valley in the 345 kV line to Sigurd. One additional 30 Mvar 138 kV shunt capacitor bank will be installed at the Red Butte substation, and one or two additional 138 kV shunt capacitor bank(s) will be installed at St. George substation.

III. Preliminary Planning Studies

The SW Utah area is served by a combination of electric utilities that provide the major transmission and generation resources, namely PacifiCorp (PAC), Utah Associated Municipal Power Systems (UAMPS), and Deseret Generation and Transmission Cooperative (DG&T). In the summer of 2002, the three utilities began joint transmission studies to determine the future transmission facility requirements for the SW Utah area. The studies were divided into two parts to determine the facility requirements for (1) the 345/138 kV transmission system back to the main grid and (2) the 138/69 kV transmission system to the local load. The 138 kV Middleton substation and 138 kV St. George substation roughly define the point of separation for the two studies. Although the studies were divided, common power flow cases with detailed 345/138/69/34.5 kV system modeling were utilized.

The transmission lines connecting Utah/Colorado with Nevada/Arizona/New Mexico are collectively referred to as the Western Electricity Coordinating Council (WECC) TOT 2 transmission path, and are divided into three subgroups:

- Colorado to New Mexico (3 transmission lines)
- Utah to Arizona/New Mexico (2 transmission lines)
- Utah to Nevada (1 transmission line)

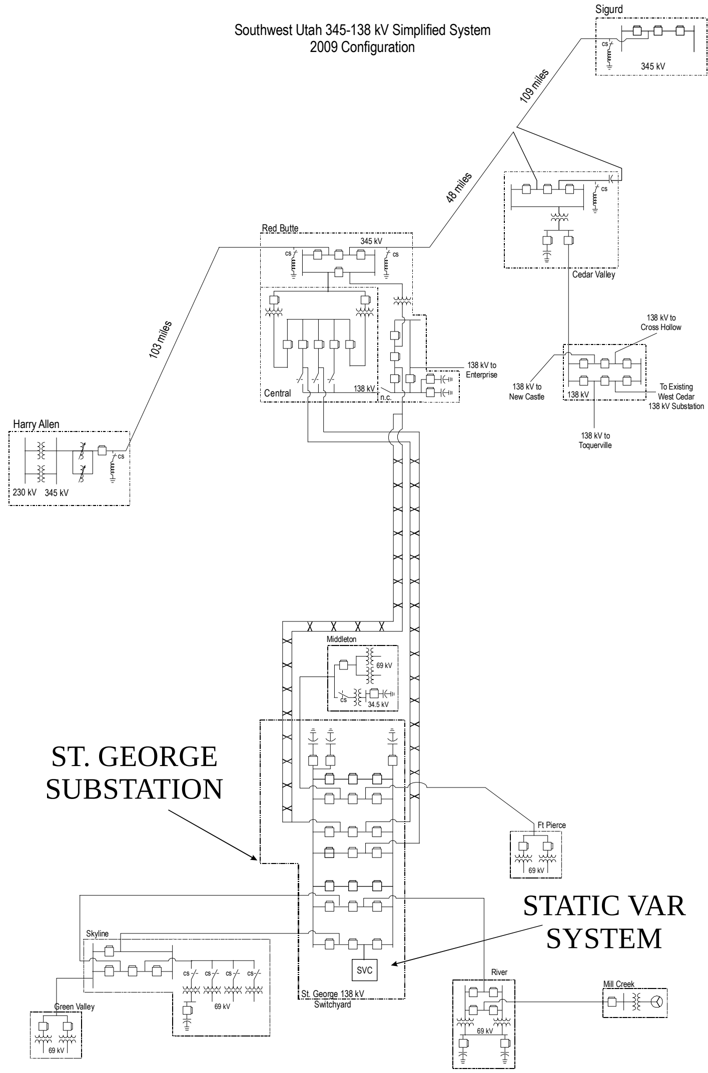

Fig. 2. 2009 Southwest Utah area simplified system one-line diagram.

A. Study Procedures

Steady state power flow, and single contingency (N-1) and double contingency (N-2) post-transient power flow studies were conducted on the 2006 heavy summer (HS) power flow cases. Studies by PacifiCorp modeling heavy simultaneous Utah to Arizona/New Mexico and Utah to Nevada as well as non-simultaneous transfers were conducted to determine facility additions required for load growth and additions required for maximum simultaneous transfers.

In general, transmission system facilities were added during the studies until acceptable system performance was achieved, or until a load level was determined for which a specific transmission system addition was needed.

A large range of studies concentrating on the 2006 summer configurations was conducted by PacifiCorp to identify required facility additions. However specific studies to identify the need and/or timing were not conducted for all of the facility additions proposed. Comparisons of study results combined with engineering judgment form the basis for these additions.

B. Performance Criteria

The PacifiCorp and WECC "Reliability Criteria for Transmission System Planning" were used to evaluate system performance. Key elements/criteria applicable to this study are summarized below.

- Steady-State
  - all voltages between 0.95 to 1.05 p.u., and all facility loadings within continuous operating limits
  - voltage deviations for shunt capacitor bank switching $\leq$ 3% in PacifiCorp criteria
- Single Contingencies (N-1)
  - voltage deviations < 5% in WECC criteria, minimum voltage of 0.90 p.u. in PacifiCorp criteria
  - all facility loadings within emergency limits
- Double Contingencies (N-2)
  - voltage deviations < 10% in WECC criteria, minimum voltage of 0.90 pu in PacifiCorp criteria
  - all facility loadings within emergency limits
  - N-2 outages include breaker failures, common corridor and double circuit line outages

C. Study Results

The 2006 configuration studies identify the need for voltage support and increased thermal capability in the transmission system serving the SW Utah load. The additions are separated into two categories, (1) facilities required to serve the growing SW Utah load and (2) facilities required for maximum simultaneous Utah to Arizona/New Mexico and Utah to Nevada transfers. Some of the facility additions to serve the load growth also help to maintain the transfer capabilities. However, additional facilities are required to achieve the established maximum simultaneous transfer levels. Facility additions are further separated into two categories (i.e., N-1, N-2) based on level of contingency indicating the need for the facility.

- The St. George SVS is required to prevent a St. George area voltage collapse for critical N-1 outages during heavy load conditions.
- In 2004, the loss of the Sigurd-Red Butte 345 kV line is the critical line outage.
- In 2005, the Red Butte-Harry Allen 345 kV line is included as a critical outage.
- In 2006, the loss of one Central-St. George or the Red Butte-St. George 138 kV line also becomes a critical outage.
- The SVS is required to provide the dynamic reactive power requirements for these critical line outages as well as to maintain the Utah to Arizona/New Mexico transfer capability as the SW Utah area load grows.
- A Red Butte SVC was studied as an alternative to the St. George SVS. While the Red Butte SVC is generally a workable alternative, the St. George SVS significantly reduces the total MVA overloading on the Red Butte/Central to St. George 138 kV transmission system for the loss of one of the lines.
- The St. George SVC also provides better St. George area voltage regulation for line outages and capacitor bank switching. The actual reactive power capability of the SVC was based on the 2006 study results and on the optimum design and reliability of the SVC.

Additional 2009 power flow study results indicates that an SVC with a capability of -35/+100 Mvar at the 138 kV bus would be required for steady-state, switching, loss of load, and major transmission line outage conditions.

The stability limiting contingency for the basis of the SVC rating is a four-cycle Cedar Valley 345 kV three phase fault with loss of the Cedar Valley-Sigurd 345 kV line. After the fault is cleared, the St. George substation 138 kV voltage ranges between 0.6 and 0.7 pu up to 1.0 second into the disturbance due to the load characteristics. Subsequently, the reactive output of the SVC at the 138 kV level ranges between 100 and 125 Mvar during this same time period. The dynamic requirement of the SVC is therefore based on approximately 100 Mvar output at 0.6 pu voltage, as determined at the 138 kV level.

IV. St. George SVS Rating and Design

Fig. 3 shows the key SVC equipment components of the St. George SVS and its connection to the 138 kV bus at the St. George substation. The "SVS" is made up of two major components: a -35 to +100 Mvar "SVC" and two 89 Mvar capacitor banks. The SVC portion is a conventional TCR/FC (thyristor-controlled reactor/fixed capacitor) SVC comprised of one 0 to -135 Mvar TCR branch, and three fixed capacitor branches tuned for harmonic filtering. The capacitive transient overload rating is achieved by switching in the two (total +64 Mvar at 0.6 p.u. voltage) MSC branches, bringing the total effective reactive compensation limit to +100 Mvar at 0.6 p.u. system voltage (or equivalently to +278 Mvar at 1.0 p.u. system voltage). Normally, the full load TCR valve conduction angle is limited to 160 degrees and results in a normal maximum TCR rating of -135 Mvar.

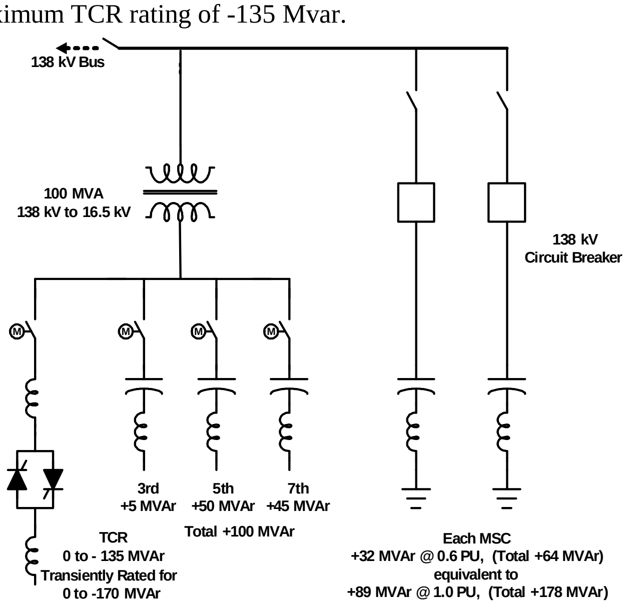

Fig. 3. One-line diagram of the St. George SVS.

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However, the TCR valve conduction angle can be increased to 180 degrees to provide an additional -35 Mvar to increase the TCR rating to -170 Mvar for 3 seconds. This TCR overload allows the MSC(s) to remain connected following a disturbance, while absorbing any excess Mvars generated by the MSC(s), for duration sufficient for reclosing operations to occur. Thus, the total equivalent controllable reactive power compensation range is transiently rated from -70 to +278 Mvar at 1.0 p.u. voltage.

The volt-reactive power (VQ) capability curve for the SVC portion of the St. George SVS is shown in Fig. 4, which illustrates the operating capabilities.

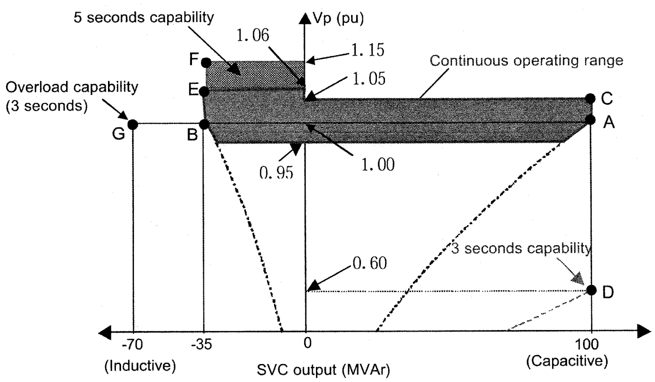

Fig. 4. VQ capability curve.

V. Overview of SVS Dynamic Performance Analysis

One of the engineering studies associated with the design of the St. George SVS was to conduct a dynamic performance analysis to demonstrate that the SVS controls the system's dynamic performance and meets the performance criteria. This is typically done by the vendor.

The requirement for voltage support in the SW Utah area was specified by PacifiCorp and was based upon the necessary amount of reactive support to maintain pre and post contingency voltages at the predefined values, and to prevent voltage collapse due to a major system disturbance.

A. Requirements For Dynamic Voltage Support

The primary objective for the SVS is to provide dynamic voltage control in the SW Utah transmission system. The SVS was designed to meet the following system performance criteria under both peak and light loading conditions.

- Post Contingency Voltage Deviation --> Post transient voltage deviations in the SW Utah area shall be less than 5% at the St. George substation 138 kV bus for single contingency 345 kV and 138 kV line outages in the SW Utah area.
- Fault Induced Delayed Recovery --> Reactive power and control capability shall be provided to facilitate voltage recovery within 1.5 seconds following a three phase 345 kV or 138 kV fault and loss of a single 345 kV or 138 kV transmission element.
- Voltage Deviation for Shunt Reactive Device Switching --> Necessary reactive power and control capability must limit St. George substation voltage deviation to less than 3% for 345 kV shunt reactor switching at Red Butte and 138 kV shunt capacitor switching at Red Butte and St. George substations.

B. SVS Stability Model

A user-written, stability model of the St. George SVS was designed and developed for the purpose of representing the SVS in dynamic simulations. As illustrated in Fig. 5, the model represents the continuously rated -35 to +100 Mvar SVC portion, in addition to the transient rating of -70 to +278 Mvar.

This model simulates a "smooth" control response SVC with additional capacity from two 138 kV, 89 Mvar MSCs operated based on regulated bus voltage thresholds (or setpoints) for defined time durations. The general control objective of the St. George SVS stability model is to maintain a desired voltage at the regulated bus by controlling/adjusting the shunt susceptance (B) of the SVS. The dynamic model requires representation in both the power flow data and the dynamics data.

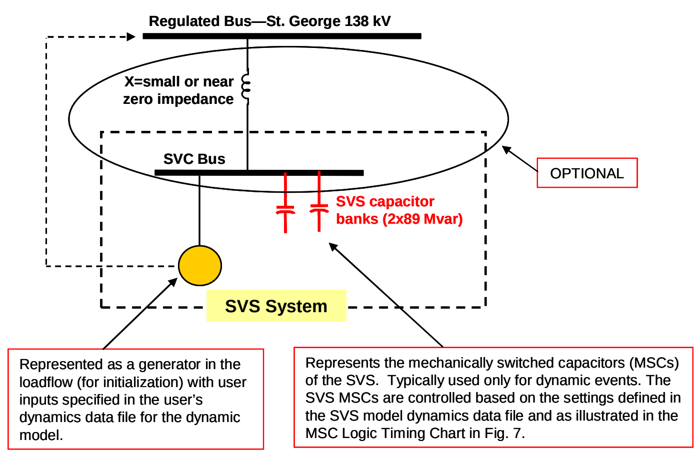

Fig. 5. Overview of the St. George SVS power flow model.

The control block diagram for the smooth-controlled -35 to +100 Mvar SVC model is shown in Fig. 6, including the settable dynamic model parameters associated with the automatic voltage regulator (AVR), susceptance (B) limits, slope reactance (Xsl), reference voltage (Vref), and lag/delay representation.

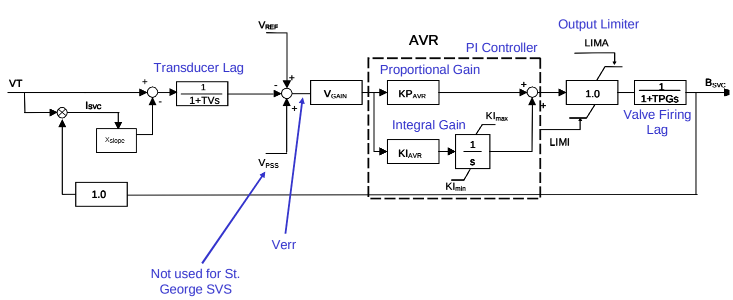

Fig. 6. Control block diagram of the SVC portion dynamic model.

The time delays and switching logic for the two 89 Mvar MSCs are shown in Fig. 7, and are settable in the dynamic data file.

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MSC1 is switched ON with a *Tdelay* of 0.08 seconds if the bus voltage is below *Vlow1* (0.6 p.u.) for a time *T11* (0.02 sec), and is switched off with a *Tdelay* if the bus voltage exceeds *Vhigh1* (1.0 p.u.) for a time *T13* (1.0 sec).

MSC2 is switched on with a *Tdelay* if the bus voltage is below *Vlow2* (0.4 p.u.) for a time *T21* (0.02 sec), and is switched off with a *Tdelay* of 0.08 seconds if the bus voltage exceeds *Vhigh2* (0.90 p.u.) for a time *T23* (0.02 sec). Tdelay represents an approximation of the time for mechanical circuit breaker operation of the breakers switching the MSCs.

When one or both MSCs are switched on, the lower "limiters" (LIMI and KImin shown in Fig. 6) of the SVC portion are set to a Ytemp value (-70 Mvar for St. George SVS) for a total accumulated time period of *T4* seconds (3 seconds) to capture the short-term inductive overload available with the St. George TCR. If or when both MSCs are switched off, *T4* stops accumulating time, however if *T4* has not timed out, the time remaining up to *T4* is available for subsequent MSC operations. T4 is a simplified representation of the thermal capability of the TCR.

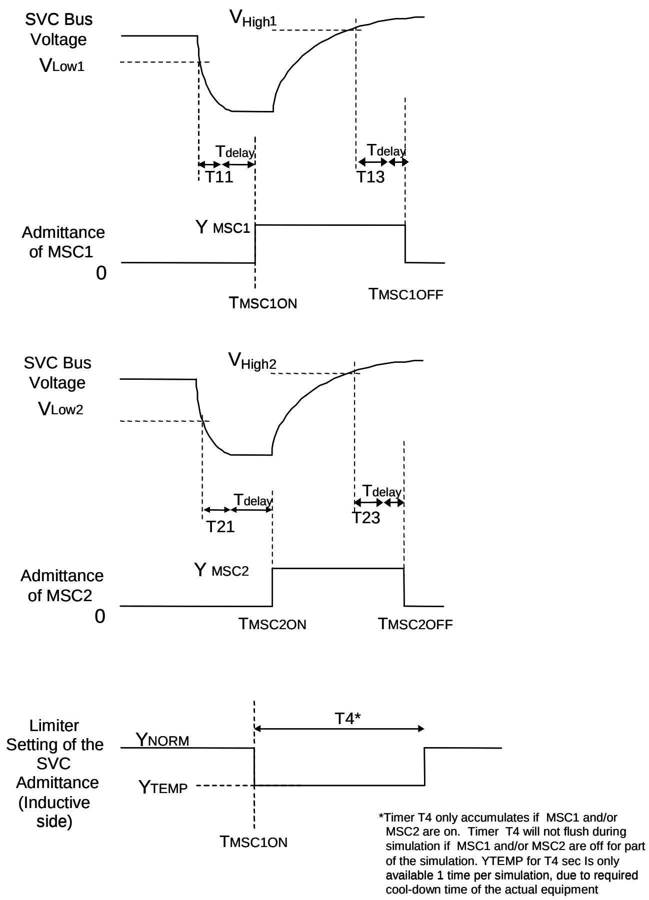

Fig. 7. Timing chart of the MSC switching logic.

C. Analysis and Results

The purpose of the dynamic performance analysis was to verify that the -35 to +100 Mvar continuously rated SVS (transiently rated at -70 to +278 Mvar) St. George SVS controls the system's dynamic performance during system disturbances.

The analysis was performed using the full PacifiCorp power flow and stability models encompassing the Western USA Interconnection. Six contingency cases were analyzed for six different power flow conditions for both heavy and light load conditions for the 2009 system. Loads within the SW Utah area above 5 MW were modeled as 45.5% induction motor loads and 54.5% constant current loads.

The most limiting case for voltage recovery is illustrated in Fig. 8 and identified as a 3-phase fault at Cedar Valley 345 kV and subsequent loss of the Cedar Valley-Sigurd 345 kV transmission line under 2009 heavy load conditions. Fig. 8 illustrates the stressed system voltage during the 1.5 second recovery primarily due to the impact of the induction motor loads. This same case without the St. George SVS results in severely depressed voltages below 0.5 p.u. following fault clearing.

This analysis has verified that the SVS continuous rating of -35 to +100 Mvar and transient rating of -70 to +278 Mvar applied at the St. George 138 kV bus controls the system dynamic performance during a wide range of disturbances and operating conditions for both 2009 heavy and light load conditions.

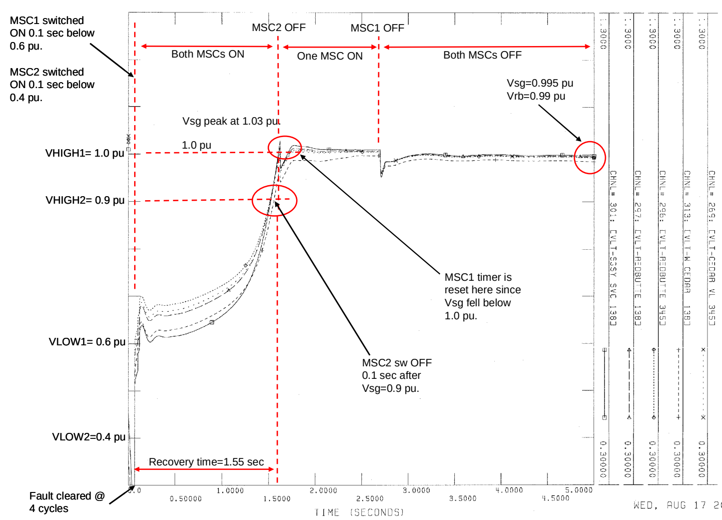

Fig. 8. Dynamic simulation plot of the limiting 2009 heavy loading contingency case, loss of the Cedar Valley-Sigurd 345 kV transmission line.

VI. Overview of Coordinated Voltage/Var Control Scheme

The St. George SVS was also required to facilitate a coordinate voltage/var scheme in the SW Utah area to regulate the Red Butte 345 kV and 138 kV bus voltage and to preserve the St. George SVC output for dynamic events.

In the year 2009, the coordinated control scheme will be required to control two 55 Mvar shunt reactors at Red Butte 345 kV bus, two 30 Mvar shunt capacitor at banks at Red Butte 138 kV bus, and three 30 Mvar shunt capacitor banks at the St. George 138 kV bus. The purpose of the Red Butte shunt line reactors and shunt capacitor banks is to regulate the Red Butte 345 kV and 138 kV bus voltages.

A voltage profile study showed that even when the St. George SVS adequately regulates the St. George 138 kV bus voltage, the voltage profile at the Red Butte 345 kV and 138 kV bus voltage can be inadequate unless coordinated controls of shunt reactive devices at Red Butte 345 kV and 138 kV bus are implemented.

To achieve appropriate voltage profiles at the Red Butte and St. George, switching control of Red Butte shunt capacitors and reactors by monitoring the voltage of Red Butte 345 kV and 138 kV was proposed. Study of various operating conditions resulted in the following bus voltage ranges:

- Red Butte 345 kV: 1.015 – 1.06 p.u.
- Red Butte 138 kV: 1.01 – 1.055 p.u.
- St. George 138 kV: 1.00 – 1.03 p.u.

The purpose of the St. George 138 kV, 30 Mvar shunt capacitor bank is to minimize the steady-state reactive power output of the St. George SVC, as recently implemented in [4].

A. *Operating Method*

Fig. 9 shows the overall coordinated control system for the SW Utah area with remote capacitor banks and reactor banks.

The coordinated control was designed based on the following concepts:

1) The voltage on the network is regulated by the SVC at first, and the role of voltage regulation is taken over by shunt capacitors and/or reactors automatically in the steady-state condition by reducing the output of the SVC gradually, so that the SVC's dynamic range can be maintained within -15 to +30 Mvar in steady-state conditions.

2) If the shunt capacitors or shunt reactors to be switched ON or OFF are not available, the SVC maintains its output for voltage support until the shunt capacitors or shunt reactors become available.

3) The SVC is controlled for the fine tuning of voltage by the switching of shunt devices, if the SVC is allowed to output the limited reactive power during the coordinated control.

4) The SVC acts as a dynamic voltage regulator during the disturbances of power system.

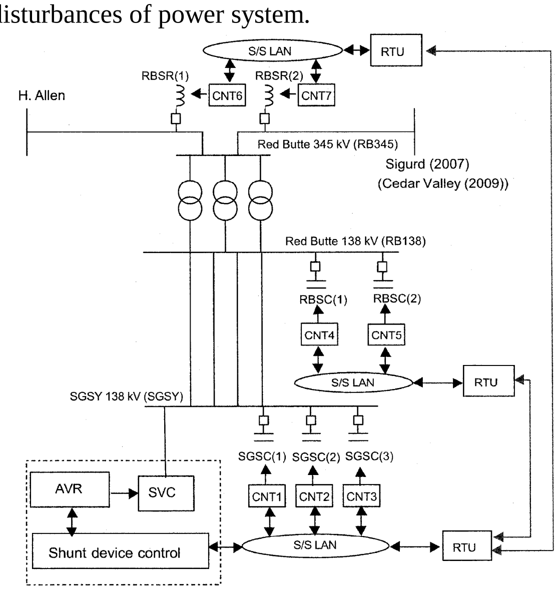

Fig. 9. Overall coordinated control system for the Southwest Utah area.

B. *Shunt Device Control*

Fig. 10 presents a basic block diagram of the coordinated controls.

The priority order of voltage/var control objectives applied to the shunt device selection logic is steady-state voltage regulation of the:

1) St. George 138 kV bus (and reducing SVC steady-state output)
2) Red Butte 138 kV bus
3) Red Butte 345 kV bus

Shunt capacitors and the shunt reactors are switched on or off according to the following operating conditions:

<u>Reactive Power Output of SVC</u>

The reactive power output of the SVC is monitored by a Var Sensor (QS). When the measured capacitive output of SVC (QC) becomes larger than the preset value (QC1) for a pre-determined time, a SC-on command signal is provided to the shunt capacitor and reactor controller. The appropriate shunt capacitor/reactor is selected and a switch-on/off command is provided to the corresponding remote shunt device through the communication system.

When the inductive output of SVC (QL) becomes larger than the preset value (QL1) for a pre-determined period of time, a SC-off command signal is provided to the shunt capacitor and reactor controller. The appropriate shunt capacitor/reactor is selected and a switch on/off command is provided to the corresponding remote shunt device through the communication network.

<u>Voltage Conditions at Red Butte Substation</u>

The voltage conditions at the Red Butte 138 kV and 345 kV buses are monitored, and the measured voltage signals are provided to the coordinated control circuit through PacifiCorp's communication network.

When the monitored voltage (V1) at the Red Butte 138 kV bus becomes lower than the preset value (VL1) or the monitored voltage (V2) at the Red Butte 345 kV bus becomes lower than the preset value (VL2), a SC-on command signal or shunt reactor off command signal is provided to the shunt capacitor/reactor controller. The appropriate shunt capacitor/reactor is selected, and a switch-on/off command is provided to the corresponding remote shunt device through the communication network.

When the monitored voltage (V1) at the Red Butte 138 kV bus becomes higher than the preset value (VH1) or the monitored voltage (V2) at the Red Butte 345 kV bus becomes higher than the preset value (VH2), a SC-off command signal or shunt reactor on command signal is provided to the shunt capacitor/reactor controller. The appropriate shunt capacitor/reactor is selected and a switch-off/on command is provided to the corresponding remote shunt device through the communication system.

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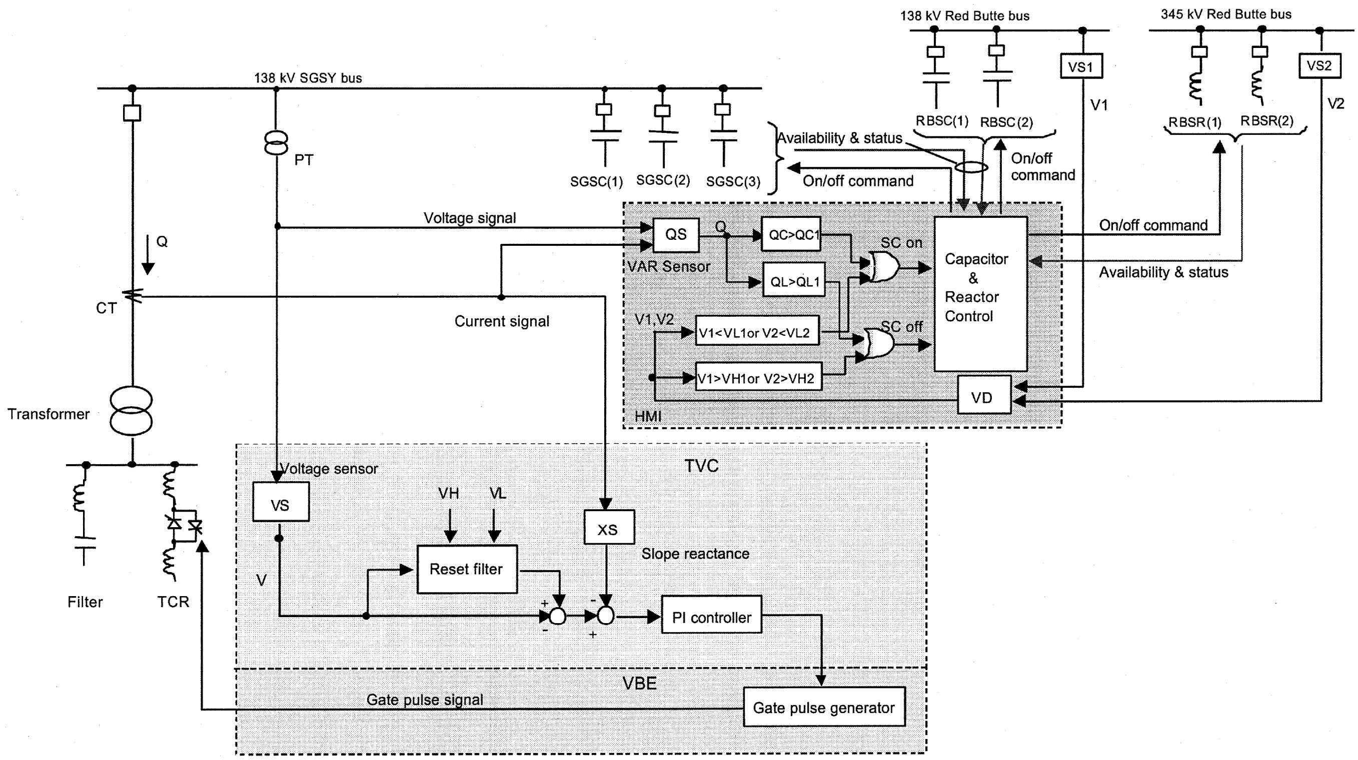

Fig. 10. Basic block diagram of the coordinated control system.

VII. Conclusion

This paper has presented an overview of a Static Var System continuously rated at -35 to +100 Mvar (transient rating -70 to +278 Mvar) applied for voltage control of the 138 kV transmission system in Southwest Utah area.

The preliminary planning studies discussed in this paper provide background on the system problem and a proposed solution that was later confirmed during pre-manufacturing dynamic performance studies. Also discussed were the SVS design and modeling and the coordinated control of local and remote shunt capacitors and reactors.

The St. George SVS was successfully installed and tested with an in-service date of June 2006.

The application of the St. George SVS and coordinated controls provides adequate voltage control in the Southwest Utah area.

VIII. References

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IX. Biographies

Dan Sullivan, John Paserba, Gregory Reed, Terry Croasdaile, Rob Westover, and Ron Pape are employed by Mitsubishi Electric Power Products, Inc. (MEPPI) based in Warrendale, PA.

Masatoshi Takeda, Satoshi Yasuda, and Hitoshi Teramoto, are employed by Mitsubishi Electric Corporation (MELCO) based in Itami, Japan.

Yoshiyuki Kono, Ken-ichi Kuroda, and Koji Temma are employed by MELCO based in Kobe, Japan.

William Hall, Duane Mahoney, and Paul Henry are employed by PacifiCorp based in Salt Lake City, Utah.

Dean Miller is employed by PacifiCorp based in Portland, Oregon.