Small Generator Interconnection System Impact Study

For

XXX

20 MW Solar PV Generating Facility

SGI-PNM-2010-02

Date: 11/26/2012

Prepared by Public Service Company of New Mexico

Foreword

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1. EXECUTIVE SUMMARY

On January 25, 2010, XXX ("Interconnection Customer") perfected a Small Generator Interconnection ("SGI") request to interconnect a new 20 MW solar Photo Voltaic ("PV") plant near Estancia, New Mexico ("Project"). The proposed Point of Interconnection ("POI") is just south of the existing Tri-State Generation and Transmission ("Tri-State") Estancia 115 kV distribution substation as shown in Figure 1 below.

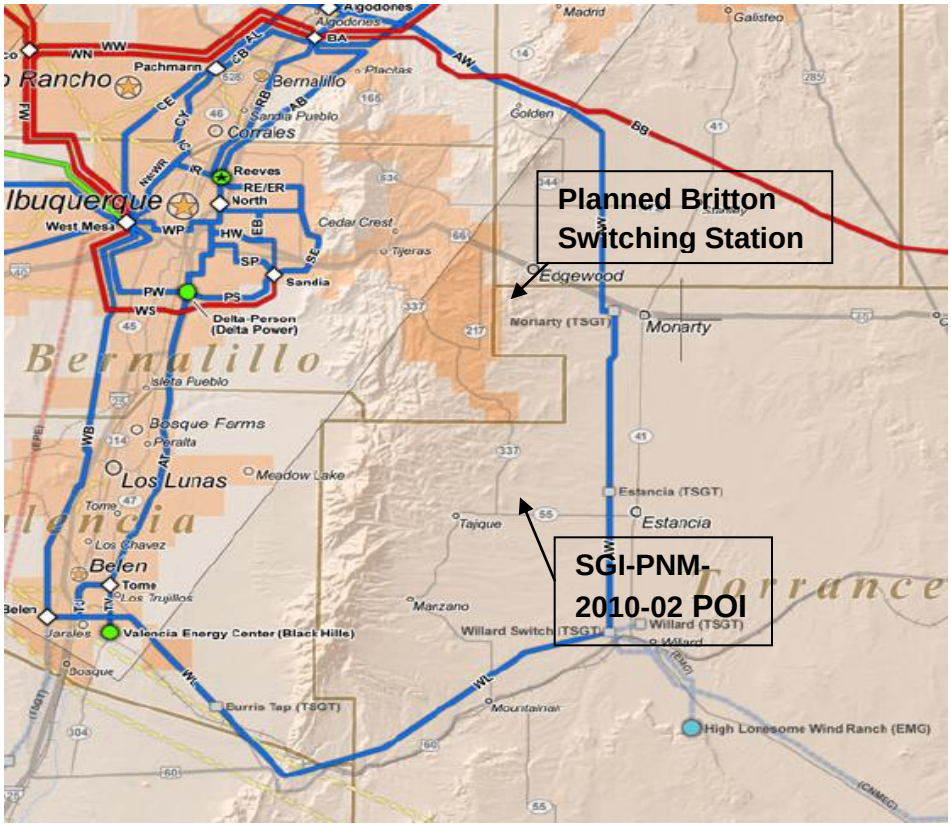


Figure 1

In response to the Interconnection Customer's request, PNM Transmission & Distribution Planning and Contracts performed an Interconnection System Impact Study ("Study") based on the assumptions, criteria and methodologies described below. The Study provided non-binding cost and construction schedule estimates for all identified system reinforcements required for interconnection at the POI.

The findings of the Study are summarized as follows:

Steady-State Performance

The powerflow analysis shows the following Network Upgrades are required to accommodate the interconnection for SGI-PNM-2010-02:

- Construction of a new four (4) terminal 115 kV ring bus switching station (expandable to a breaker and half scheme) just south of the Tri-State owned Estancia distribution substation on the Willard–Britton 115 kV line section of the Willard-Algodones 115 kV line.

- Addition of one (1) 115 kV terminal at the planned PNM Britton 115 kV switching station on the Willard– Algodones 115 kV line.

- Construction of a new 16.6 mile 115 kV transmission line from the POI just south of the Tri-State owned Estancia distribution substation to the planned PNM Britton 115 kV switching station.

Dynamic Stability Performance

The dynamic stability analysis had acceptable system performance for all single (n-1) and double (n-2) contingencies.

Short Circuit Analysis

Previous short circuit analysis for similar projects located near Estancia have shown that this Project will not increase short-circuit duty at any existing stations beyond equipment ratings and, as a result, will not require additional network upgrades to insure facilities are adequate for expected worst case short circuit duty.

POI Reactive Power Analysis

The reactive power analysis indicates reactive power capability of the Project is adequate to achieve a +/- 0.95 net power factor range at the POI.

It should be noted that the simplified equivalent collector system provided by the Interconnection Customers for the solar facilities do not allow for a detailed evaluation of reactive requirements from each individual solar panel to the POI. This analysis only provides an indication of reactive power requirements and it remains the Interconnection Customer's responsibility to design their generation facilities and additional supplemental reactive support to meet the requirements at the POI.

Conclusion

The cost estimate and schedule for the necessary Network Upgrades for SGI-PNM-2010-02 are summarized below:

Upgrades Required		
System Upgrade	**Project Costs ($M)**	**Construction Time**
Construct a new four (4) breaker ring 115 kV switching station at POI just south of Estancia 115 kV	7	24 months
Expand the planned PNM Britton 115 kV switching station by adding one breaker	1	24 months
Construct a new 16.6 mile 115 kV transmission line (795 kcmil ACSR) from a new switching station at the POI to planned PNM Britton 115 kV substation	9.96	36 months
Total	**17.96**	**36 months**

2. INTRODUCTION

On January 25, 2010, XXX ("Interconnection Customer") perfected a Small Generator Interconnection ("SGI") request to interconnect a new 20 MW solar PV plant near Estancia, New Mexico ("Project"). The proposed Point of Interconnection ("POI") is just south of the existing Tri-State Generation and Transmission ("Tri-State") Estancia 115 kV distribution substation. The Project interconnection to the PNM transmission system is shown in Figure 2.

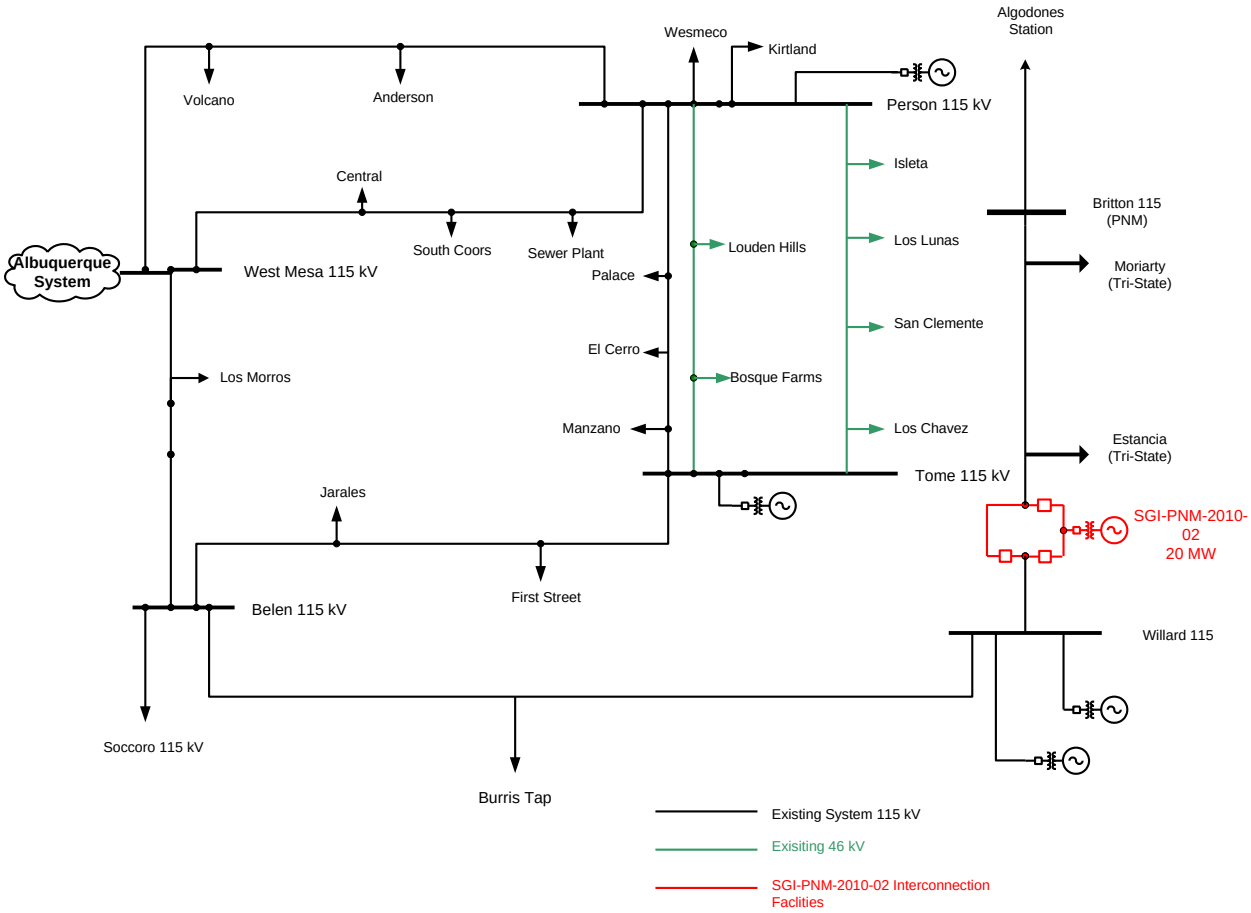


Figure 2

In response to the Interconnection Customer's request, PNM Transmission & Distribution Planning and Contracts will perform an Interconnection System Impact Study ("Study") based on the assumptions, criteria and methodologies described below. The Study will also provide non-binding cost and construction schedule estimates for all identified system reinforcements required for interconnection at the POI.

3. STUDY CRITERIA

3.1 Thermal and Voltage Criteria

The steady-state performance criteria applicable to powerflow analysis in the Study are shown in Table 1. The criteria are NERC/WECC performance requirements as well as applicable additions and exceptions for the New Mexico transmission system.

Table 1. Powerflow Performance Criteria

Area	Conditions	Loading Limits	Voltage (p.u.)	Voltage Drop	Application
EPEC (Area 11)	Normal	< Normal Rating	0.95 - 1.05		69kV and above
			0.95 - 1.07		Artesia 345 kV
			0.95 - 1.08		Arroyo 345 kV PST source side
			0.90 - 1.05		Alamo, Sierra Blanca and Van Horn 69kV
	Contingency	< Emergency Rating	0.925 - 1.05	7%	60 kV to 115 kV
			0.95 - 1.07	7%	Artesia 345kV
			0.95 - 1.08	7%	Arroyo 345kV PST source side
			0.90 - 1.05		Alamo, Sierra Blanca and Van Horn 69kV
			0.95 - 1.05	7%	Other 345 kV buses
PNM (Area 10)	Normal ALIS	< Normal Rating	0.95-1.05		46 kV and above*
	Contingency N-1	< Emergency Rating	0.925 - 1.08^	6 %**	46 kV to 115 kV
			0.90 – 1.08^	6 %**	230 kV and above
	Contingency N-2	< Emergency Rating	0.90 - 1.08^	10 %	46 kV and above*
Tri- State (zones 120-123)	Normal ALIS	< Normal Rating	0.95-1.05		All buses
	Contingency N-1	< Emergency Rating	0.90-1.1	6 %***	69 kV and above except Northeastern NM and Southern NM
			0.90-1.1	7 %***	69 kV and above in Northeastern NM and Southern NM
	Contingency N-2	< Emergency Rating	0.90-1.1	10%	All buses

*Taiban Mesa and Guadalupe 345 kV voltage 0.95 and 1.1 p.u. under normal and contingency conditions.
**For PNM buses in southern New Mexico (Zones 104,130, 131, and 132), the allowable N-1 voltage drop is 7%.
*** Tri-State Voltage Criteria, April 2008 – Correspondence to TSS.
^ Provided operator action can be utilized to adjust voltages back down to 1.05 pu

- All equipment loadings must be below their normal ratings under normal conditions.
- All line loadings must be below their emergency ratings for both single and double contingencies. All transformers and equipment with emergency rating should be below their emergency rating.

3.2 Generator Reactive Power Range Criteria

The procedure used for evaluating the reactive power requirements is contained in PNM's interconnection requirements for generators.[1] In this approach, a power flow simulation is conducted both with and without the Project generation enabled on the post-project base case. The Project-enabled case represents the reactive power range at full output and control capability described in the interconnection application. The power flow simulation is conducted to determine whether voltage at the POI or adjacent transmission nodes differs by more than 1.0% for normal or contingency conditions without other generators in the area regulating voltage. These units can be taken off line if necessary when performing this evaluation. If it does, then supplemental reactive power support to achieve a +/- 0.95 power factor range at the POI shall be required.

[1] See PNM FAC-001-R2.1.3 - VOLTAGE LEVEL AND MW/MVAR CAPACITY OR DEMAND.

3.3 Transient Stability Performance Standard

The NERC/WECC transient stability performance requirements for transmission contingencies are as follows:

- All machines will remain in synchronism.
- All voltage swings will be well damped.
- Following fault clearing for single contingencies, voltage on load buses may not dip more than 25% of the pre-fault voltage or dip more than 20% of the pre-fault voltage for more than 20 cycles. For N-2 and breaker failure contingencies, voltage on load buses may not dip more than 30% of the pre-fault voltage or dip more than 20% of the pre-fault voltage for more than 40 cycles.

Table 2—PNM Fault Clearing Times

Fault Type	Voltage (kV)	Clearing Time (near-far end breakers—see note below)
3 Phase Normally Cleared	345	4–4 Cycles
	230	4–4 Cycles
	115	4–4 Cycles
Fault Type	**Voltage (kV)**	Clearing Time (normally opened breaker both near and far end—breaker opened due to stuck breaker both near and far end
1 Phase* Stuck Breaker	345	4-12 Cycles
	230	
	115	4-15 Cycles

3.4 Voltage Ride-Through Requirement

Generators connected to the PNM transmission system are required to meet the voltage ride-through requirements contained in PRC-024-WECC-CRT-0-Low Voltage Ride Through Criterion[2]. In this case, SGI-PNM-2010-02 is expected to ride through (i) three-phase faults, cleared in normal time and (ii) single-line-to-ground faults with delayed clearing at Estancia.

It should be noted that positive-sequence, reduced-order simulation models for PV plants do not allow for a detailed evaluation of voltage ride-through. The interconnection studies only provide an indication of risk, and it remains the Interconnection Customer's responsibility to design the Project to meet the ride-through requirement.

3.5 Interconnection Requirements

Consistent with FAC-001 R1.1, PNM's Interconnection Facilities will be designed to maintain the integrity of the existing PNM transmission equipment, provide for termination of the Interconnection Customer facilities while maintaining transmission maintenance flexibility, and

[2] http://www.wecc.biz/library/Documentation Categorization Files/Regional Criteria/PRC-024-WECC-CRT-0 Low Voltage Ride Through Criterion Effective Date 4-8-2005.pdf

provide protection of the PNM Transmission System from a failure within the Interconnection Customer facilities and risk associated with three terminal line protection. As a minimum, PNM requires a three-breaker ring bus configuration for a single generation interconnection to the Bulk Electric System.

4. BASE CASE DEVELOPMENT

A WECC 2016 heavy (peak load) summer case (2016hs2) and 2015 heavy winter case (2015-16 HW2A) were used to develop the base cases. Generation dispatch and generation displacement modifications were added as discussed below.

4.1 Generation Dispatch

Proposed generation projects in the Project area holding a senior position in PNM's generator interconnection queue and their respective transmission system reinforcements are included in the base cases. Certain existing or proposed projects outside the Project area which do not have an impact on the Project are excluded or were not dispatched. Table 3 shows the generation pattern for existing and proposed generation projects.

Table 3 – Generation Dispatch

Unit	Nameplate Rating	Summer Peak Output Level*	Winter Output Level*
Four Corners Unit 1	192	0	0
Four Corners Unit 2	192	0	0
Four Corners Unit 3	256	0	0
Existing Reeves 1	43	0	0
Existing Reeves 2	44	0	0
Existing Reeves 3	66	0	0
Existing Delta-Person	132	0	0
Existing Valencia Energy Facility	143	143	0
Existing Taiban Mesa Wind Project	200	200	200
Existing Aragonne Mesa Wind Project	90	90	90
Existing Red Mesa Wind Project	100	100	100
Existing High Lonesome Mesa Project	100	100	100
Proposed Taiban Mesa II Project	50	50	50
Proposed Torrance Biomass Project	37.5	37.5	37.5
Proposed Granada Wind Project	300	300	300
Proposed Arabella Solar Project	300	0**	0**
Proposed Delta-Person Expansion	90	0	0
Proposed La Sierrita Wind Farm	70	0**	0**
Proposed Reeves Repower Project	140	0	0

Proposed Pajarito Project	176	0	0
Proposed El Cabo Wind	300	0**	0**
Proposed Mountainair Wind Project	100	0**	0**
Proposed Dunmoor Wind	700	0**	0**

**Energy Resource – set to 0 since output will be curtailed if system improvements are required.

Blackwater is scheduled at 50 MW west in both on and off peak powerflow cases. The Project generation displaces San Juan Unit 4 generation.

In the heavy summer base case, the pre-Project case has a Southern New Mexico Import (SNMI) level of approximately 265 MW while the Northern New Mexico Import (NNMI) level is approximately 900 MW. The Arroyo Phase Shifting Transformer (PST) is scheduled at 60 MW southbound. The Blackwater HVDC converter is scheduled at 50 MW westbound.

In the winter base case, the pre-Project case has an SNMI level of approximately 430 MW, while the NNMI level is approximately 740 MW. The Arroyo Phase Shifting Transformer (PST) is scheduled at approximately 200 MW southbound. The Blackwater HVDC converter is scheduled at 50 MW Westbound.

Key transmission assumptions include:

- A Gallup to PEGS 115 kV line rating of 96 MVA.
- A second Springer – Gladstone 115 kV line with a rating of 169 MVA.
- A Springer – Storrie Lake 115 kV line rating of 102 MVA.
- The Rio Puerco Phase III transmission project in service.
- A Clapham – Rosebud 115 kV line rating of 169 MVA.

Key resource related assumptions included:

- Retiring Four Corners Units 1, 2 and 3 and displacing the output with other Arizona resources.
- Adjusting Arizona resources to offset output of senior queued interconnection projects in New Mexico.
- Adjusting Arizona resources to offset output of resources associated with transmission service requests.
- Dispatching the TA-3 15 MW and 20 MW units to serve projected Los Alamos load.
- Setting the planned Gladstone 230 kV phase shifting transformer to hold a 150 MW north to south schedule.

The following senior queued interconnection projects on third party transmission systems are modeled:

- TI-04-1214[3] Wind project generating 88 MW
- Cimarron PV Solar facility generating 16.8 MW

The following Transmission Service Requests are modeled

- TSR 73152312 (80 MW) – Ojo 345 kV to Four Corners 345 kV
- TSR 74116380 (20 MW) – Ojo 345 kV to Four Corners 345 kV
- TSR 71452501 (50 MW) – Blackwater 230 kV to Four Corners 345 kV
- TSR 73140963 (90 MW) – Willard 115 kV to Four Corners 345 kV
- TSR 73140972 (10 MW) – Willard 115 kV to Four Corners 345 kV
- TSR 71639149 (90 MW) – Guadalupe 345 kV to Four Corners 345 kV
- TSR 74559236 (102 MW) – Red Mesa 115 kV to Four Corners 345 kV
- TSR 76410780 (37 MW) – Willard 115 kV to Four Corners 345 kV
- TSR 74623905 (300 MW) – Guadalupe 345 kV to Four Corners 345 kV

4.2 Project Data

The corresponding equivalent representations for the Project parameters are listed below and reflect data provided by the Interconnection Customer.

Interconnection Transmission Line:

Distance: 500 feet
Voltage: 115 kV
Positive sequence impedance on 100 MVA base:
R = 0.0002482 p.u. X = 0.00054175 p.u. B = 0.0000704692 p.u.
Zero sequence impedance on 100 MVA base:
R = 0.00047718 p.u. X = 0.0020059 p.u.

Generator Data:

Nameplate rating:	0.5 MW (40 inverters)
Reactive:	+/- .90 power factor controlled
Terminal voltage:	.270 kV

Generator Pad Mounted Transformer Configuration:

Rating:	25 MVA (20 pad-mounted at 1.25 MVA each)
Voltage Ratio	34.5 kV/0.270 kV
Impedance	R= 0.0030 p.u., X= .0750 p.u. on 25 MVA base

Collector System Impedance on 100 MVA base:

[3] http://www.tristategt.org/OASIS/documents/TI-04-1214 SIS Final Report_RAL3.pdf

R = .002758 p.u. X = 0.00507355 p.u. B = 0.00000759 p.u.

Station Step-Up Transformer Configuration:

Rating:	(ONAN/FA/FA): 18/24/32 MVA
Voltage Ratio	34.5/115/13.8 kV
Impedance	R = 0.00258 p.u., X = 0.0956 p.u., 18 MVA base

5. LIST OF CONTINGENCIES

The power flow contingencies evaluated in this study are listed in Table 4 and Table 5 below.

Table 4 - List of N-1 Contingencies

N-1 Contingencies	Pre-Project	Post-Project
FOUR CORNERS-RIO PUERCO	X	X
SAN JUAN-RIO PUERCO 345	X	X
WESTMESA-SANDIA 345	X	X
BA-NORTON 345	X	X
RIO PUERCO-WESTMESA 345	X	X
RIO PUERCO-BA 345	X	X
WESTMESA-ARROYO PS 345	X	X
RIOPUERCO 345/115 XFMR	X	X
ALGODONES-PACHMANN 115	X	X
BA-REEVES1 115	X	X
BA-REEVES2 115	X	X
BA-PACHMANN 115	X	X
CORRALES-PACHMANN 115	X	X
PERSON-TOME 115	X	X
BELEN-TOME 115	X	X
BRITTON-WILLARD 115	X	
ALGODONES-BRITTON 115	X	X
BRITTON-ESTANCIA 115		X
WILLARD-ESTANCIA 115		X
WEST MESA 3-BELEN 115	X	X
BELEN-WILLARD 115	X	X
FOUR CORNERS-SAN JUAN 345	X	X
FOUR CORNERS-SHIPROCK 345	X	X
SAN JUAN-SHIPROCK 345 kV	X	X
SOCORRO-BELEN_PG 115	X	X
SGI-PNM-2010-02		X

Table 5 - List of N-2 and Breaker Failure Contingencies

N-2 Contingencies	Pre-Project	Post-Project
RIO PUERCO-BA 1&2 345	X	X
ALGODONES-PACHMANN-BA 115	X	X
ALGODONES-PACHMANN-WESTMESA 115	X	X
BELEN-TOME & BELEN-WILLARD 115	X	X

Lists of the N-1 and N-2 contingencies evaluated for system stability are provided in Table 6 and Table 7, respectively.

Table 6– N-1 Contingencies

Disturbance Case #	Disturbance	Fault Location	Fault Type
1	WESTMESA-ARROYO PS 345	WEST MESA 345	3-Phase
2	RIO PUERCO-WESTMESA 345	RIO PUERCO 345	3-Phase
3	RIO PUERCO-BA 345	BA 345	3-Phase
4	PERSON-TOME 115	TOME 115	3-Phase
5	BELEN-TOME 115	TOME 115	3-Phase
6	ESTANCIA-BRITTON 115	ESTANCIA 115	3-Phase
7	ESTANCIA-WILLARD 115	ESTANCIA 115	3-Phase

Table 7 – N-2 Contingencies

Disturbance Case #	Disturbance	Fault Location	Fault Type
8	BELEN-TOME & BELEN-WILLARD 115	BELEN 115	3-Phase
9	BELEN-TOME 115 + TOME 115/46 XFMR	TOME 115	3-Phase

6. REACTIVE POWER ANALYSIS

To assess reactive power requirements, a power flow simulation is conducted both with and without the Project generation in service. The cases with generation in service model the reactive power range of each respective generator and the control capability as specified by the customer in the interconnection application. The power flow simulation is conducted to determine whether voltage at the POI or adjacent transmission nodes differs by more than 1.0% for normal or contingency conditions. If it does, then supplemental reactive power support to

achieve a +/- 0.95 power factor range at the POI shall be required if the reactive capability specified by the customer does not meet this range.

The results of this analysis under contingency conditions are shown in Table 8 using the reactive capability of the projects as provided by the customers. For both the heavy summer and heavy winter cases, the voltage change at the POI under contingency conditions meets or exceeds the 1.0% voltage change criteria.

Powerflow results modeling the reactive capability of the Project indicate sufficient reactive range to meet +/- .95 requirements at the POI.

Table 8. Voltage Change Analysis at the POI

Bus	Contingency	Pre-Project HS	Post-Project HS	Post - Pre % HS Voltage Change
ESTANCIA 115 kV	BELEN-WILLARD 115 kV (WL)	0.961	0.996	3.64%
Bus	**Contingency**	**Pre-Project HW**	**Post-Project HW**	**Post - Pre % HW Voltage Change**
ESTANCIA 115 kV	BELEN-WILLARD 115 kV (WL)	0.991	1.01	1.92%

7. POWERFLOW ANALYSIS

Powerflow results show that for summer peak and winter peak conditions, the Project meets voltage performance criteria. Tables 9 and 10 show that there are line overloads from the POI (near Estancia 115 kV) to Moriarty 115 kV for the Belen-Willard 115 kV N-1 contingency. A rebuild of the existing line has been ruled out in previous study efforts due to reliability concerns associated with providing service to existing customers during construction. In order to mitigate this overload, a new 16.6 mile 115 kV transmission line will need to be constructed from the POI to the planned PNM Britton 115 kV switching station. These Network Upgrades are illustrated in Figure 3.

Table 9 Heavy Summer Contingency p.u. Loading

Contingency	Monitored Element	MVA Rating	Pre-Project	Post-Project
N-1				
Belen-Willard 115 kV	Estancia-Moriarty 115 kV	130	<.95	1.064
Belen-Willard 115 kV	Estancpn 115.00-Estancia 115 kV	130	.976	1.131
N-2				
Willard-Belen-Tome 115 kV	Estancia-Moriarty 115 kV	130	<.95	1.064
Willard-Belen-Tome 115 kV	Estancpn 115.00-Estancia 115 kV	130	.976	1.131

Table 10 Heavy Winter Contingency p.u. Loading

Contingency	Monitored Element	MVA Rating	Pre-Project	Post-Project
N-1				
Belen-Willard 115 kV	Estancia-Moriarty 115 kV	130	<.95	1.093
Belen-Willard 115 kV	Estancpn 115.00-Estancia 115 kV	130	.983	1.137
N-2				
Willard-Belen-Tome 115 kV	Estancia-Moriarty 115 kV	130	<.95	1.092
Willard-Belen-Tome 115 kV	Estancpn 115.00-Estancia 115 kV	130	.983	1.137

The N-2 overloads shown in Table 9 and Table 10 will be mitigated by the addition of the line between Estancia and Willard so additional mitigations for the N-2 contingencies is not required.

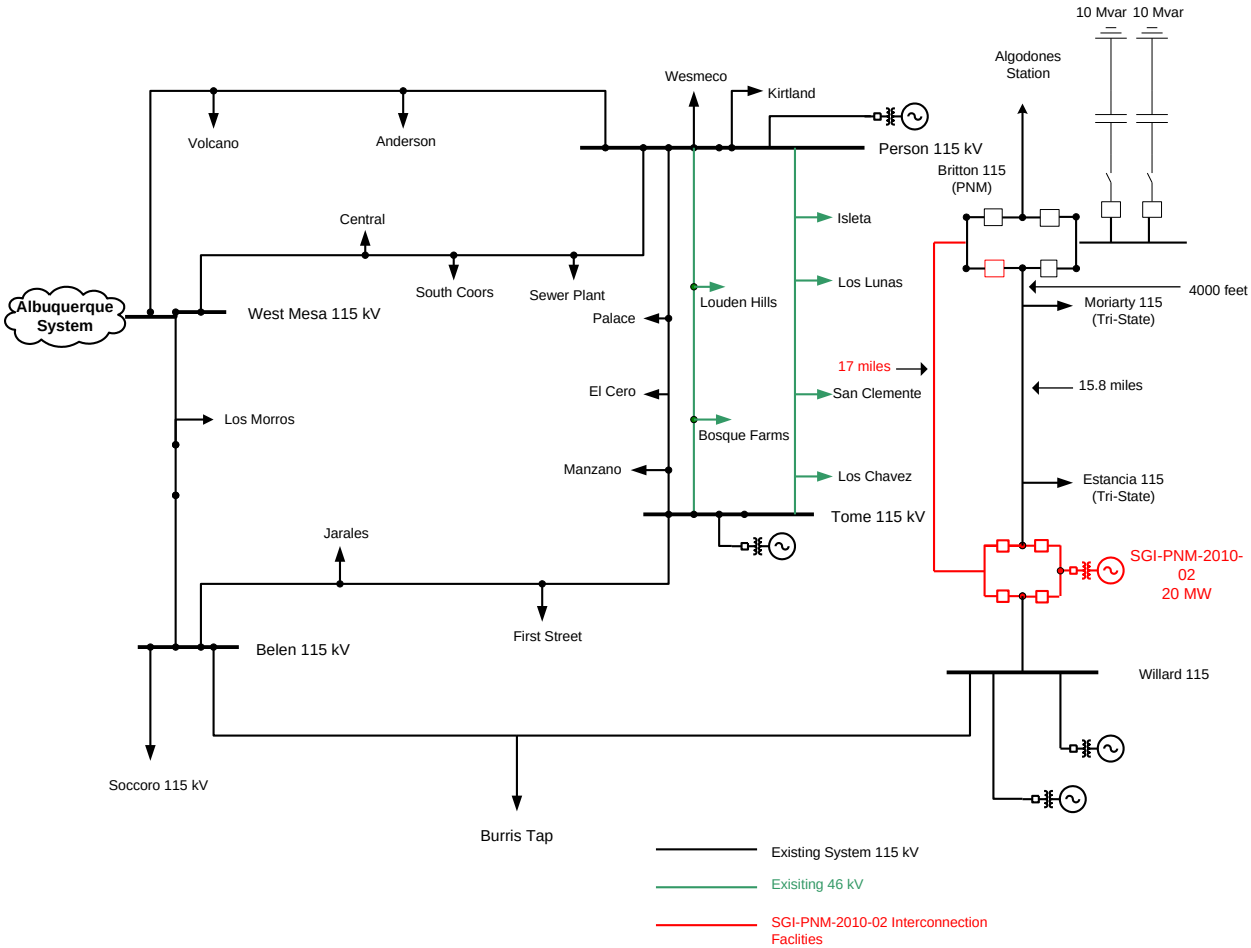


Figure 3

8. STABILITY ANALYSIS

For the stability analysis, N-1 and N-2 contingencies were considered for both the heavy summer and light winter cases. For each of the cases, the Post-Project system response was found to be in compliance with transient stability criteria. Transient stability simulation plots are included in Appendix B.

The stability results also showed that the post-Project system met voltage-ride-through requirements. It should be noted that positive-sequence, reduced-order simulation models for PV plants do not allow for a detailed evaluation of voltage ride-through. The interconnection studies only provide an indication of risk, and it remains the Interconnection Customer's responsibility to design the Project to meet the ride-through requirement.

9. SHORT CIRCUIT ANALYSIS

Previous short circuit analysis for similar Projects located near Estancia have shown that this Project will not increase short-circuit duty at any existing stations beyond equipment ratings and, as a result, will not require additional network upgrades to insure facilities are adequate for expected worst case short circuit duty.

10. COST AND CONSTRUCTION TIME ESTIMATES

Table 11. Upgrades Required

Upgrades Required		
System Upgrade	**Project Costs ($M)**	**Construction Time**
Construct a new four (4) breaker ring 115 kV switching station at POI just south of Estancia 115 kV	7	24 months
Expand the planned PNM Britton 115 kV switching station by adding one breaker	1	24 months
Construct a new 16.6 mile 115 kV transmission line (795 kcmil ACSR) from a new substation at the POI to the planned PNM Britton 115 kV substation	9.96	36 months
Total	**17.96**	**36 months**

The following general assumptions apply to all PNM cost estimates and schedules:

1. For all estimates, pricing is based on 2012 unit costs. With likely fluctuations in the price of raw materials, fuel, and labor, actual costs may vary in future years.
2. Cost estimates are considered to be within +/- 20%.
3. Estimates include, rights-of-way, governmental permitting, design, materials, construction, construction management, and internal utility loads.
4. Project schedules are considered reasonably accurate but can be affected by permitting delays, equipment deliveries, weather, availability of workforce, and availability of outage clearance for construction.
5. The proposed schedule for final design and construction is estimated to take 36 months from an authorization to begin work.

Additional details are included in Appendix C.

11. CONCLUSION

Steady-State Performance

The powerflow analysis shows the following upgrades are required to accommodate the interconnection for SGI-PNM-2010-02:

- Construction of a new four (4) terminal 115 kV ring bus switching station (expandable to a breaker and half scheme) just south of the Tri-State owned Estancia distribution substation on the Willard–Britton 115 kV line section.

- Addition of one (1) 115 kV terminal at the planned PNM Britton 115 kV switching station on the Willard–Britton 115 kV line.

- Construction of a new 16.6 mile 115 kV transmission line from the POI just south of the Tri-State owned Estancia distribution substation to the planned PNM Britton 115 kV substation.

Dynamic Stability Performance

The dynamic stability analysis had acceptable system performance for all single (n-1) and double (n-2) contingencies.

Short Circuit Analysis

Previous short circuit analysis for similar Projects located near Estancia have shown that this Project will not increase short-circuit duty at any existing stations beyond equipment ratings and, as a result, will not require additional network upgrades to insure facilities are adequate for expected worst case short circuit duty.

POI Reactive Power Analysis

The reactive power analysis indicates reactive power capability of the Project is adequate to achieve a +/- 0.95 net power factor range at the POI.

It should be noted that the simplified equivalent collector system provided by the Interconnection Customers for the solar facilities do not allow for a detailed evaluation of reactive requirements from each individual solar panel to the POI. This analysis only provides an indication of reactive power requirements and it remains the Interconnection Customer's responsibility to design their

generation facilities and additional supplemental reactive support to meet the requirements at the POI.

12. APPENDIX A: Powerflow Maps

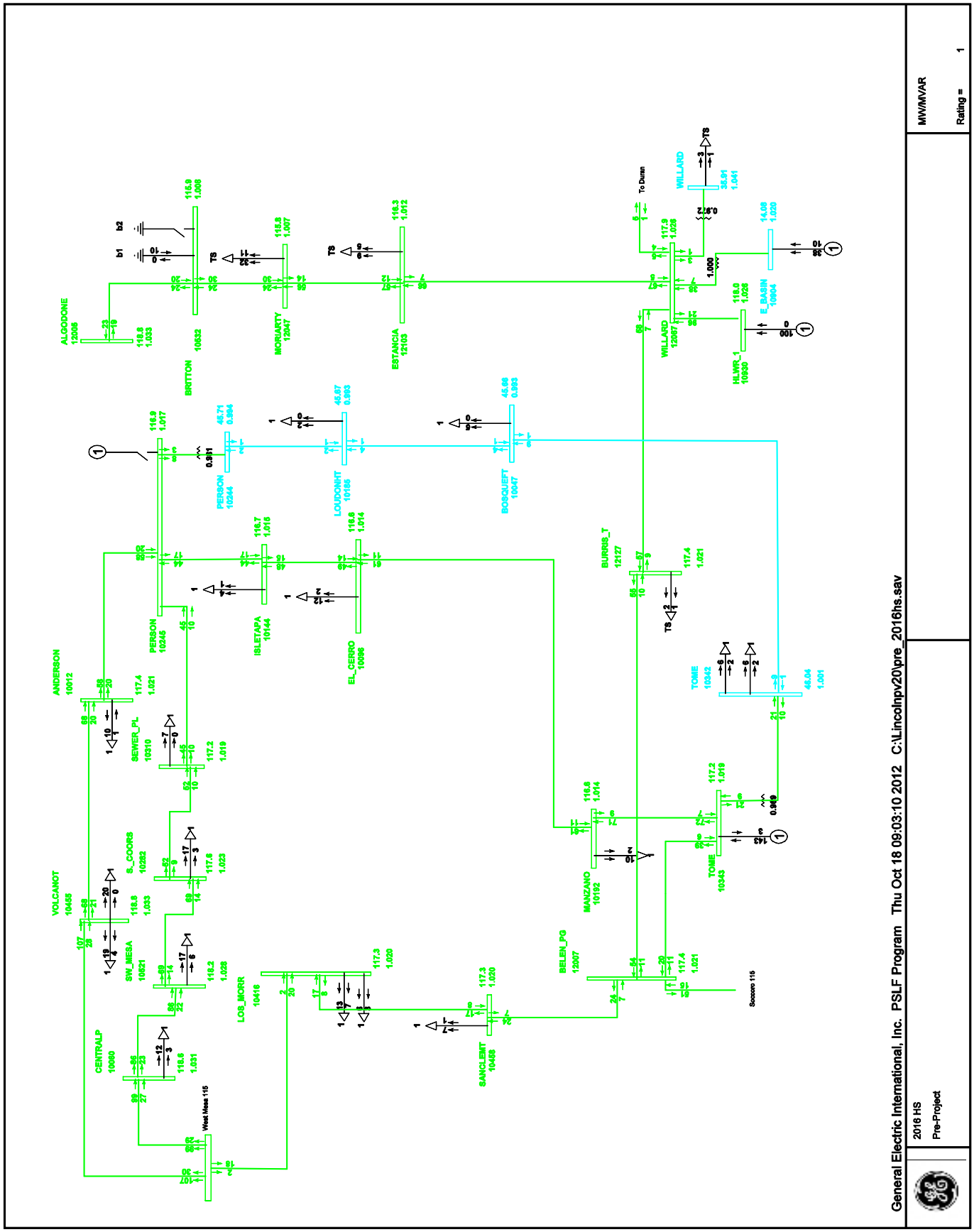


Figure A-1--Pre-Project 2016 HS

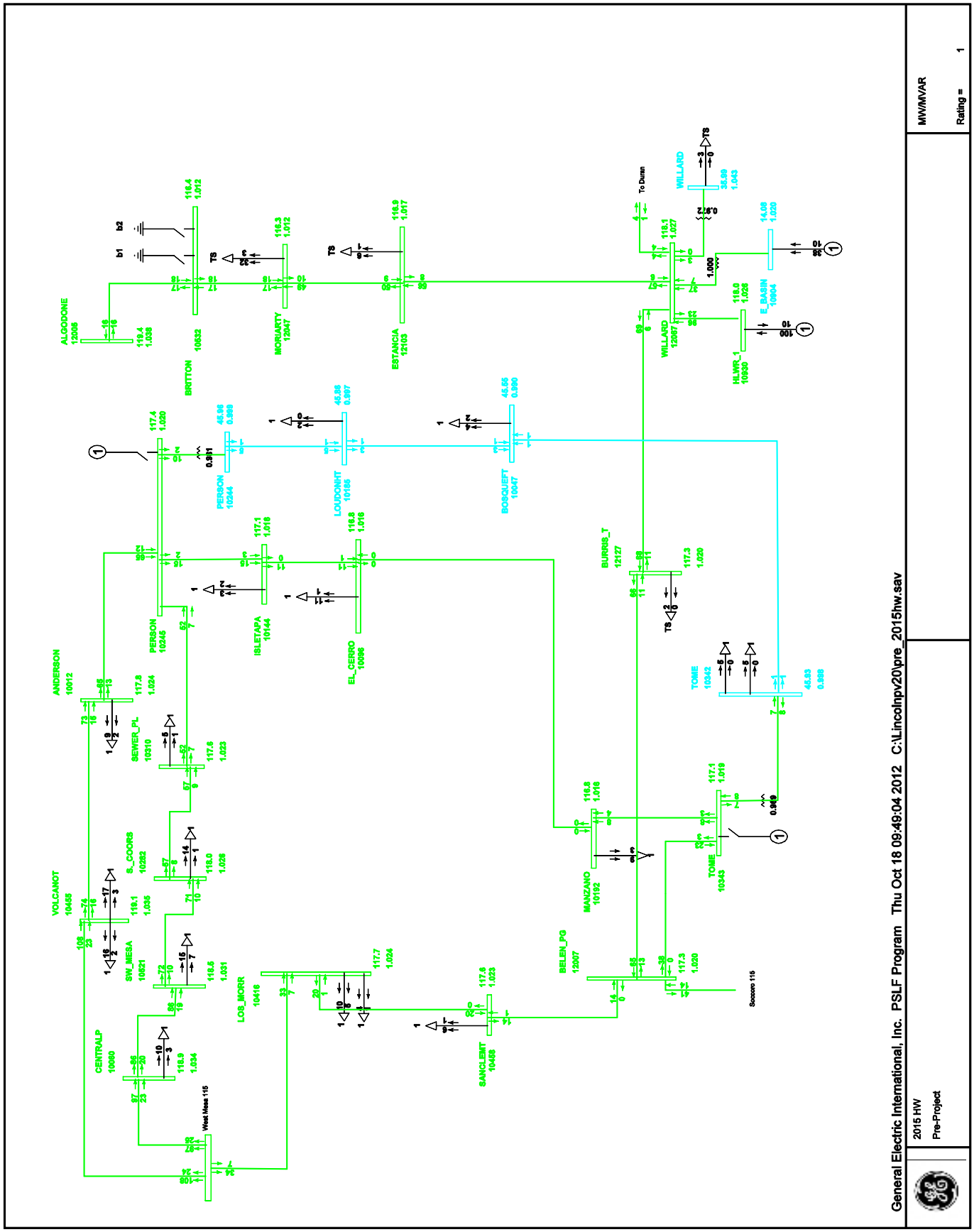


Figure A-2--Pre-Project 2015 HW

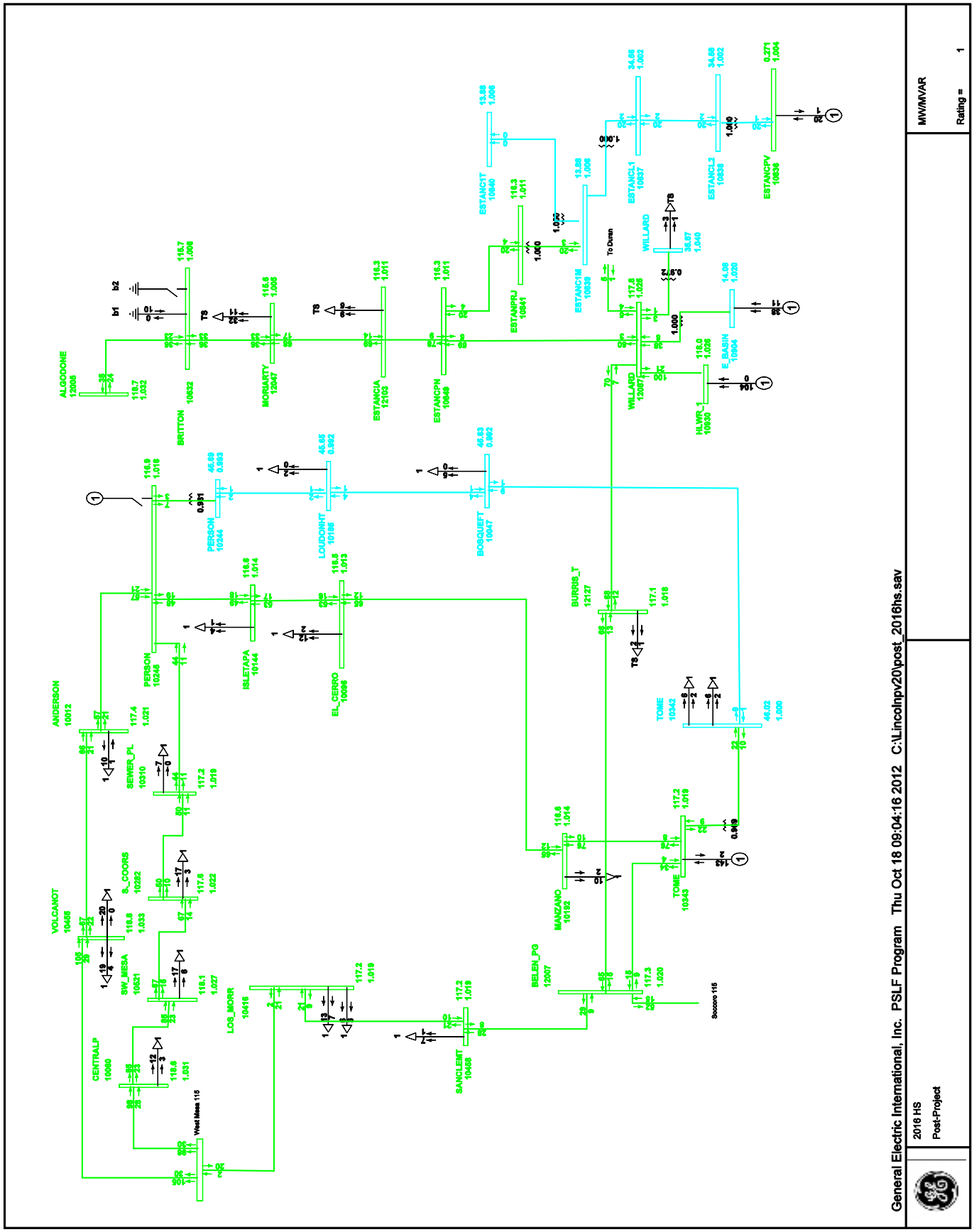


Figure A-3--Post-Project 2016 HS

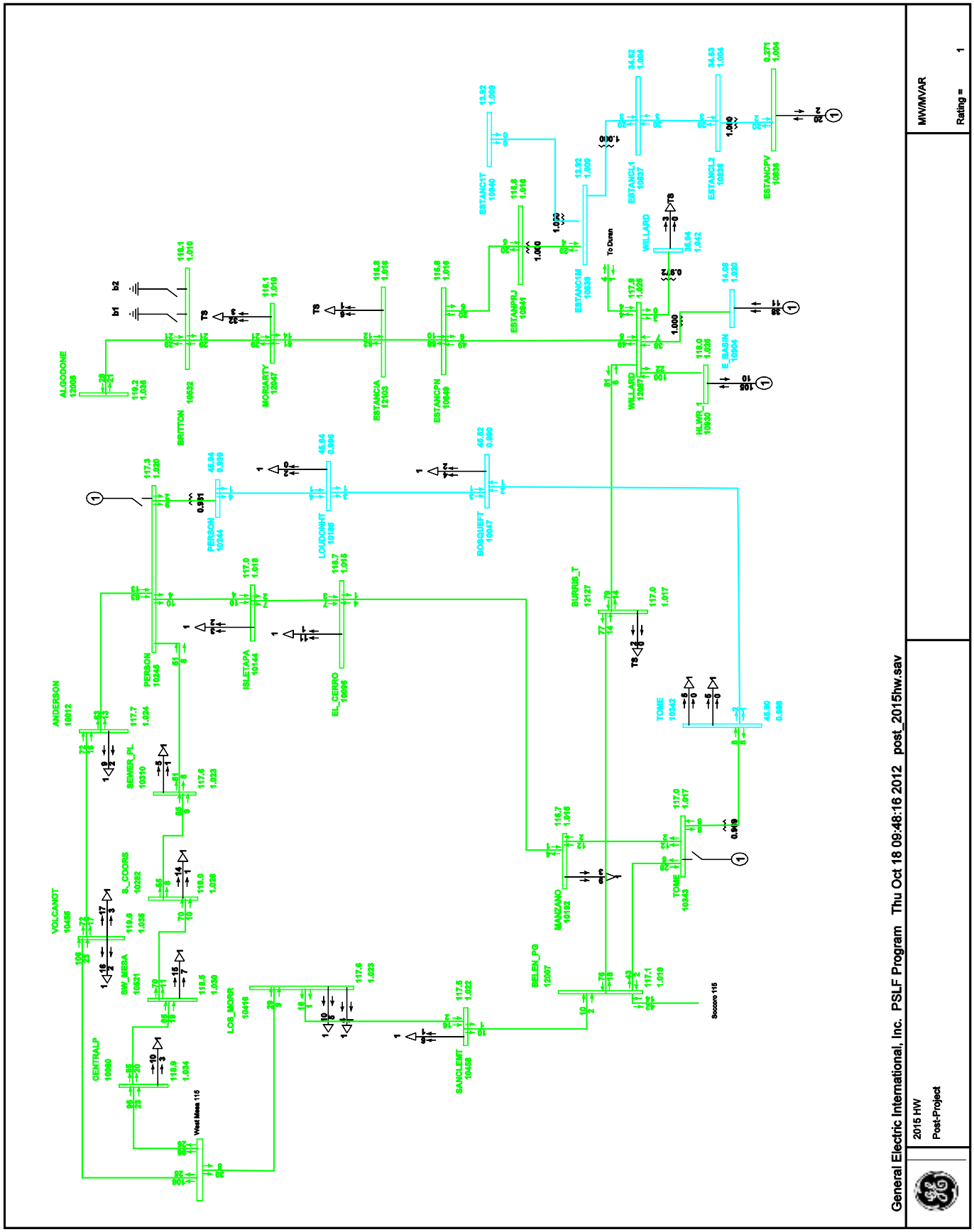
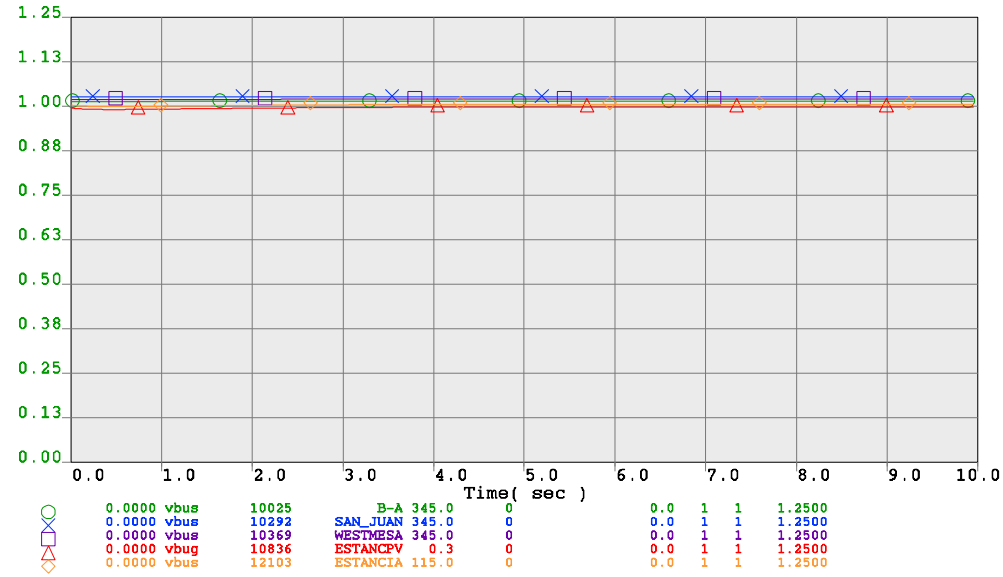
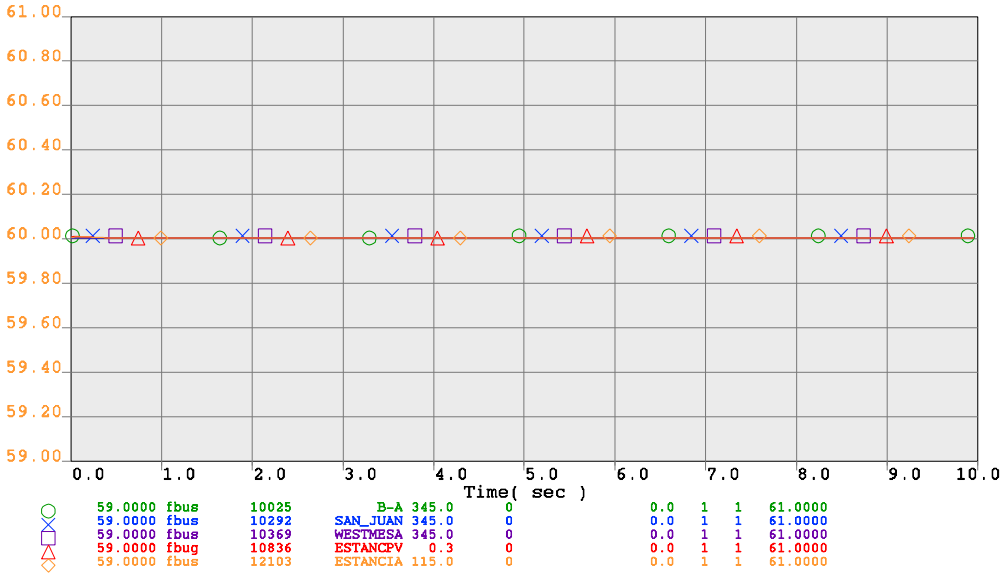


Figure A-4--Post-Project 2015 HW

13. APPENDIX B: Stability Plots





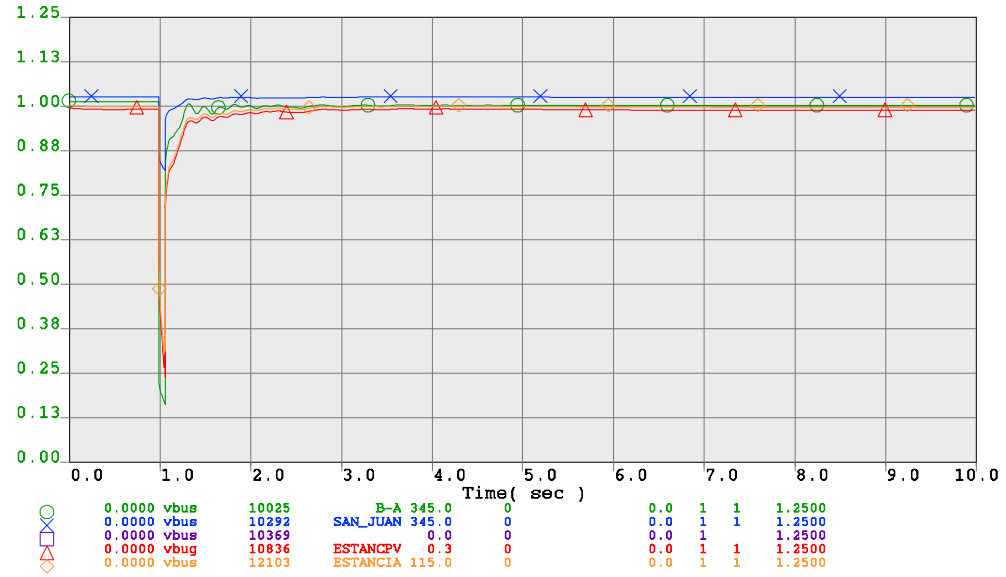
TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
No Disturbance

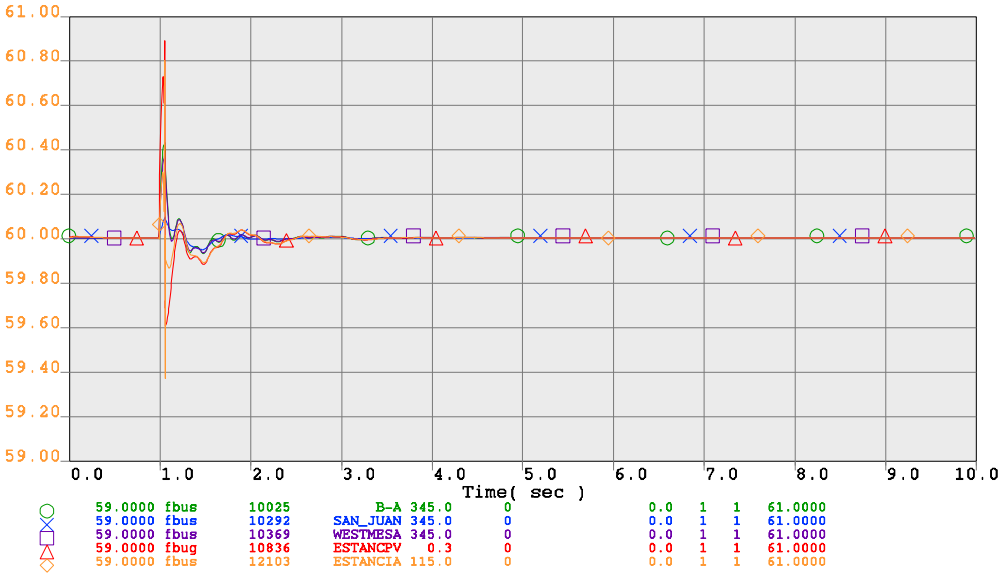
Page 1

nodisturbl20posths.chf

Tue Sep 25 10:20:34 2012

Figure B-1--2016 HS----No Disturbance--Voltage and Frequency Plots





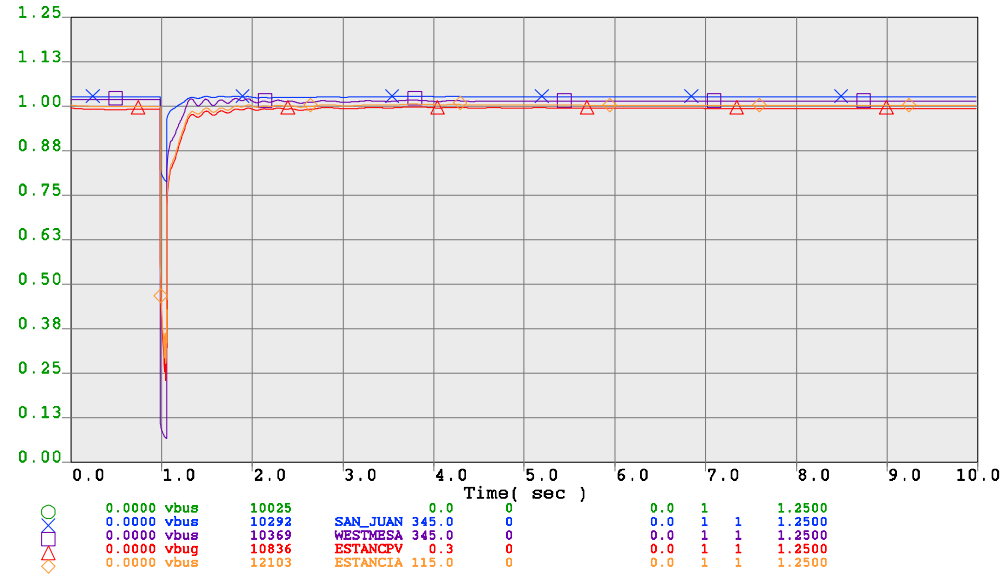
TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at West Mesa 345 kV bus;
Trip West Mesa-Arroyo in 4 cycles.

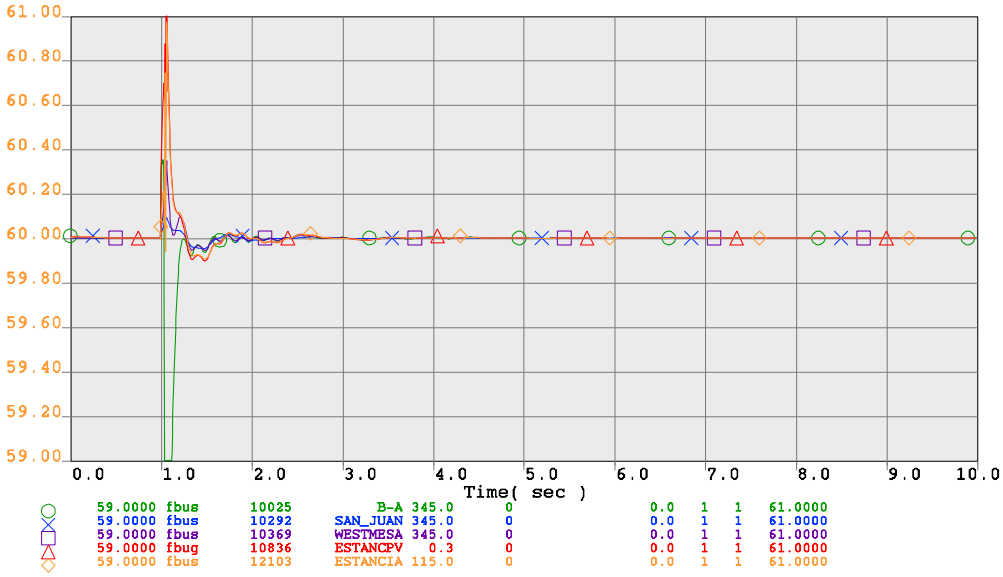
Page 1

120_hs_sav_post_EP.chf

Tue Sep 25 10:21:22 2012

Figure B-2--2016 HS----3 Phase Fault at West Mesa 345 kV; Open West Mesa to Arroyo 345 kV line--Voltage and Frequency Plots





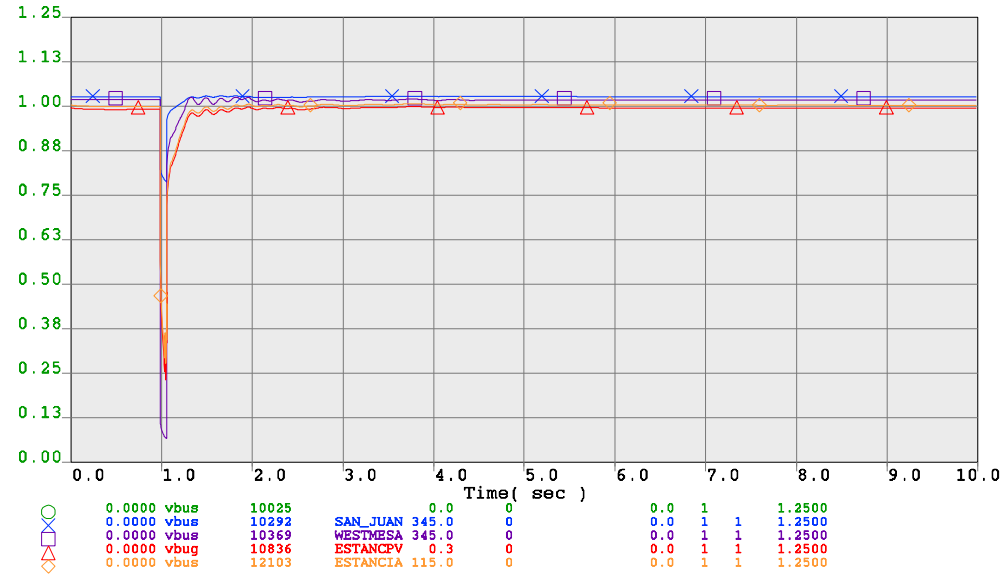
TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at Rio Puerco 345 kV bus;
Trip Rio Puerco-West Mesa 345 kV Line in 4 cycles.

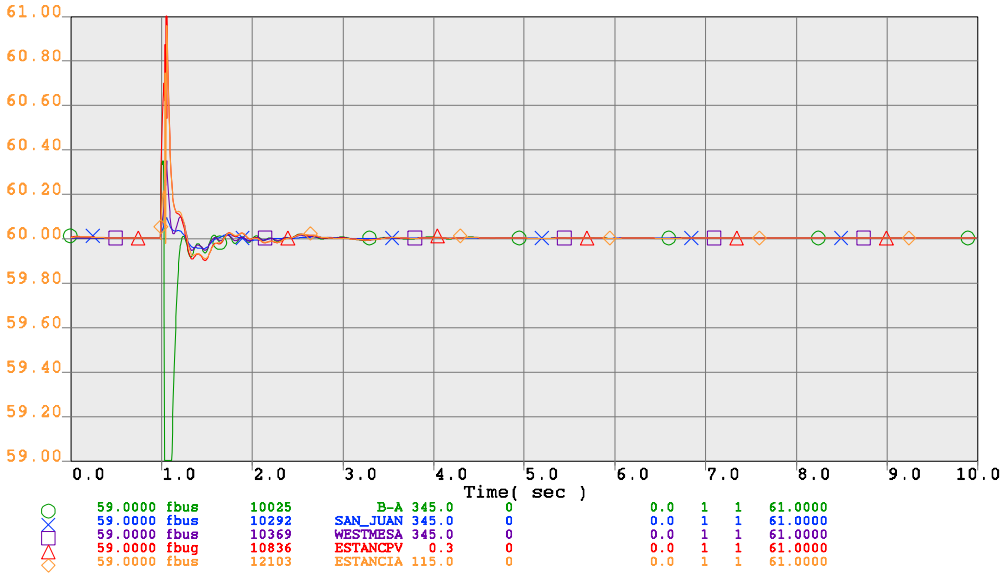
Page 1

120_hs_sav_post_RPWM.chf

Tue Sep 25 10:20:41 2012

Figure B-3--2016 HS----3 Phase Fault at Rio Puerc 345 kV; Open Rio Puerco to West Mesa 345 kV line--Voltage Plots





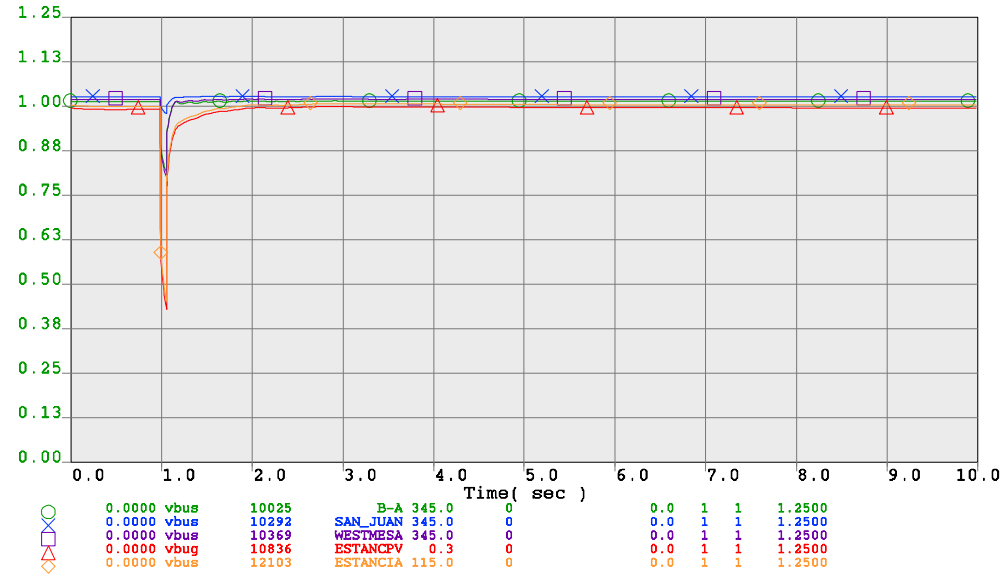
TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at BA 345 kV bus;
Trip Rio Puerco-BA 345 kV Line in 4 cycles.

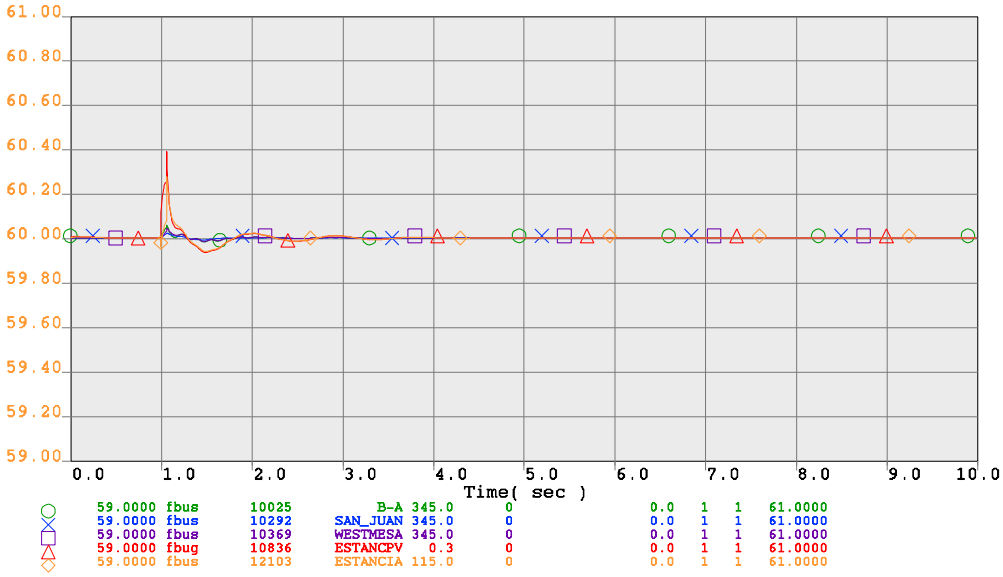
Page 1

120_hs_sav_post_RPBA.chf

Tue Sep 25 10:20:48 2012

Figure B-4--2016 HS----3 Phase Fault at BA 345 kV; Open Rio Puerco to BA 345 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at TOME 115 kV bus;
Trip PERSON-TOME 115 kV Line in 4 cycles.

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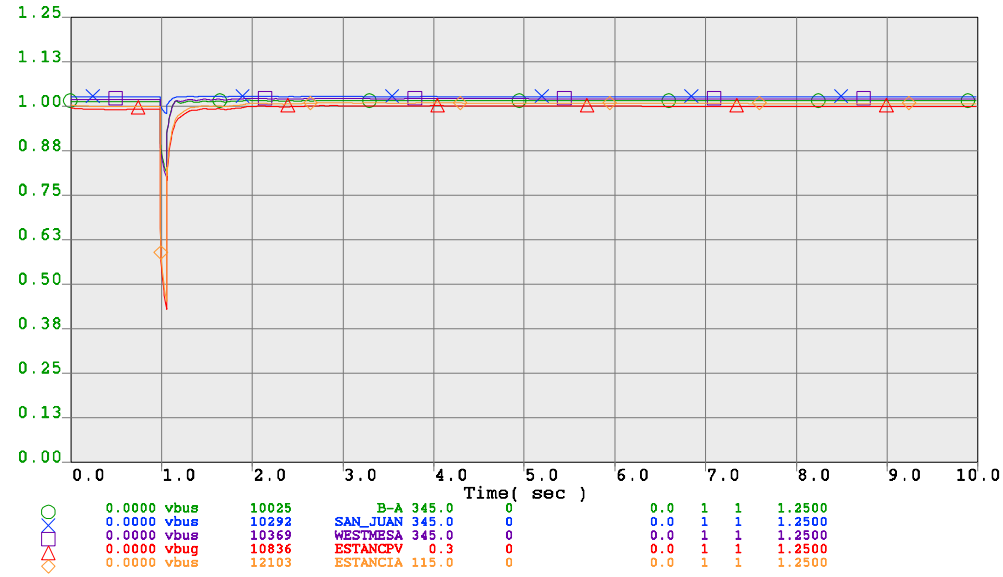
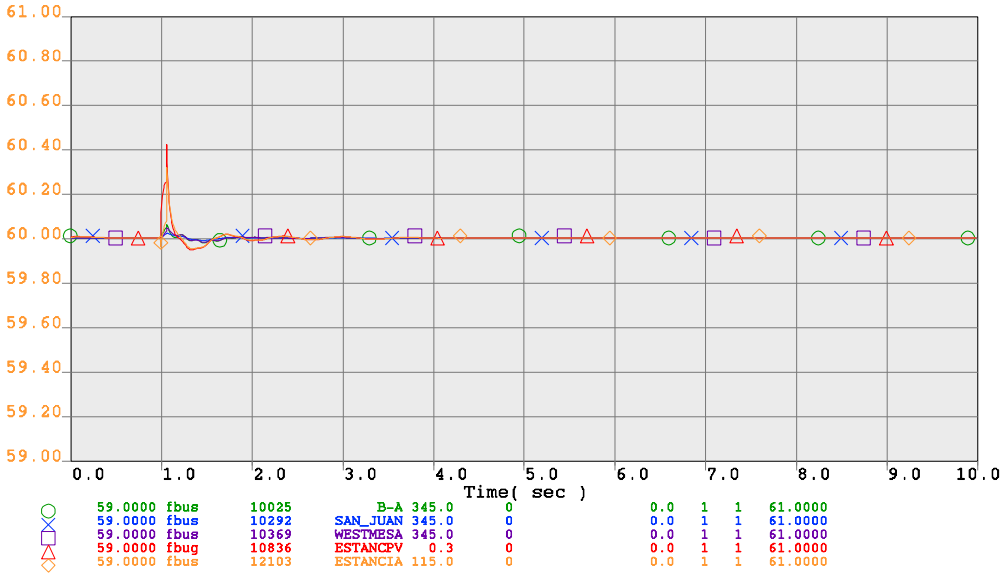
120_hs_sav_post_PERTOME.chf

Tue Sep 25 10:21:01 2012

Figure B-5--2016 HS----3 Phase Fault at TOME 115 kV; Open PERSON to TOME 115 kV line--Voltage Plots





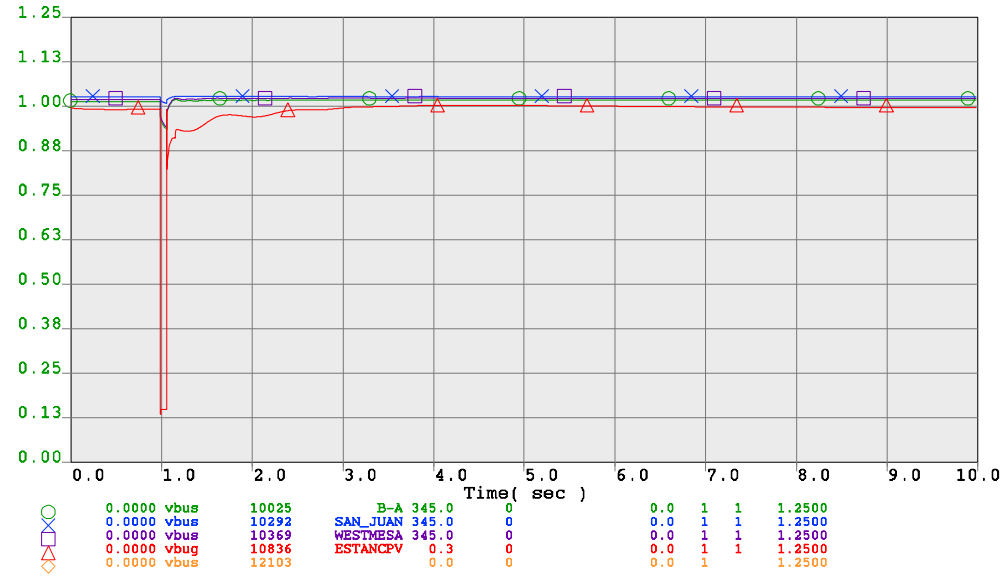
TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME 115 kV Line in 4 cycles.

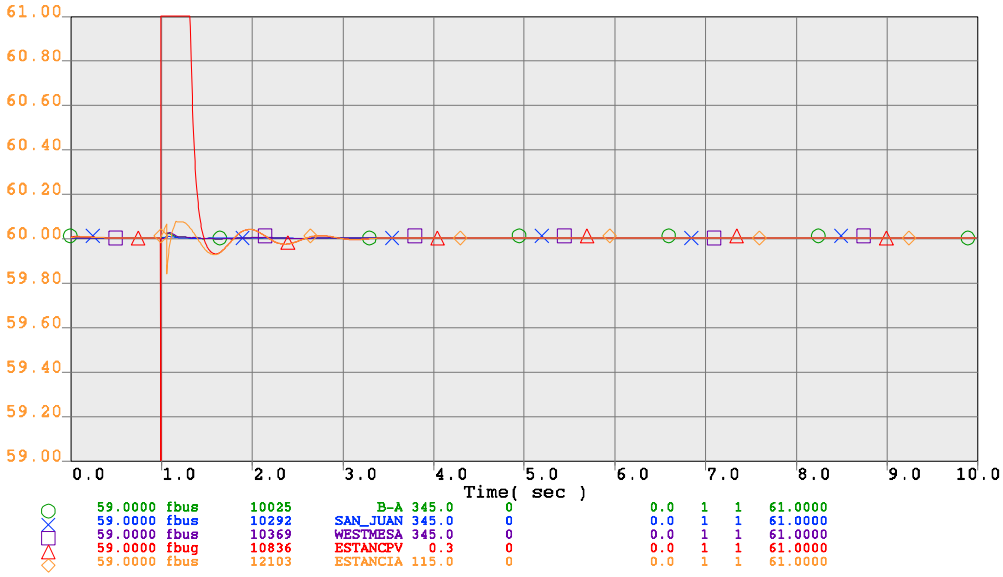
Page 1

120_hs_sav_post_BELTOME.chf

Tue Sep 25 10:20:55 2012

Figure B-6--2016 HS----3 Phase Fault at TOME 115 kV; Open BELEN to TOME 115 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to TORRANCE_PNM 115 kV line in 4 cycles.

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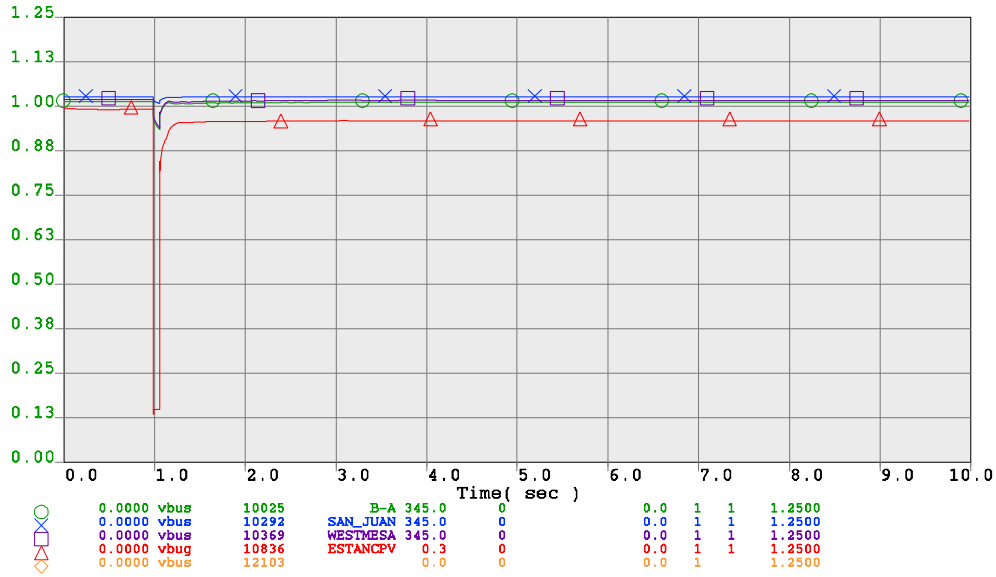
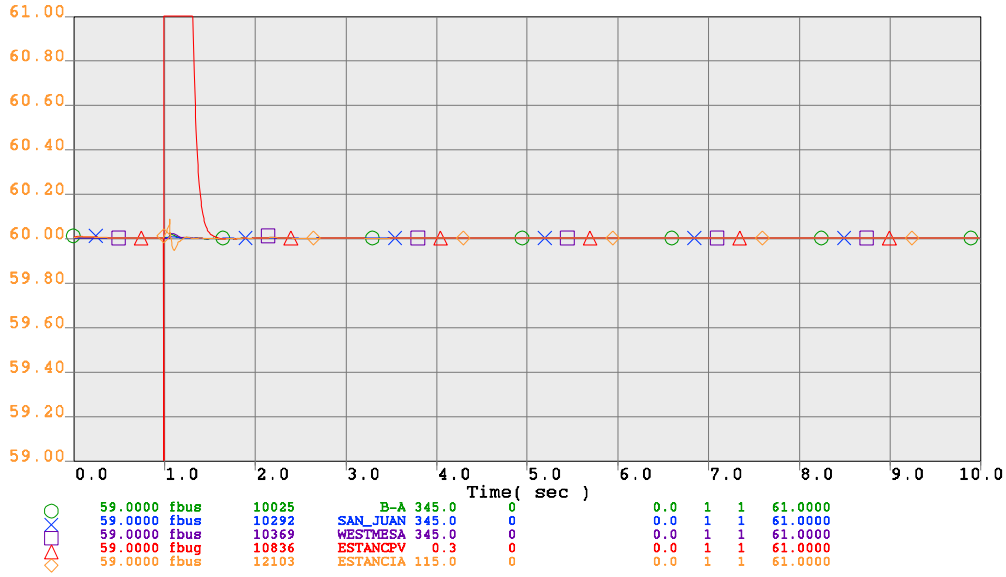
120_hs_sav_post_TorrEst.chf

Tue Sep 25 16:37:47 2012

Figure B-7--2016 HS----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to Britton 115 kV line--Voltage Plots





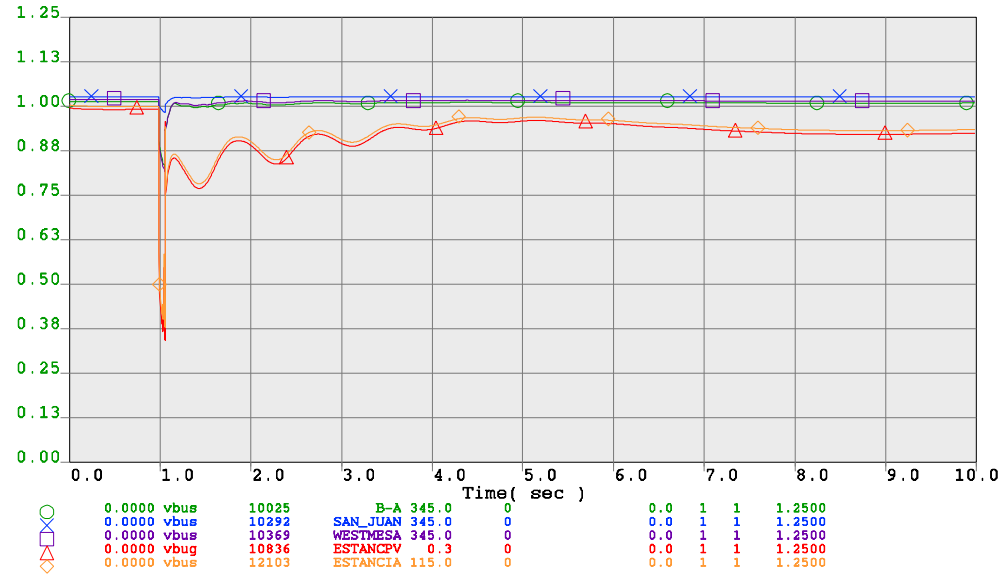
TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to WILLARD 115 kV line in 4 cycles.

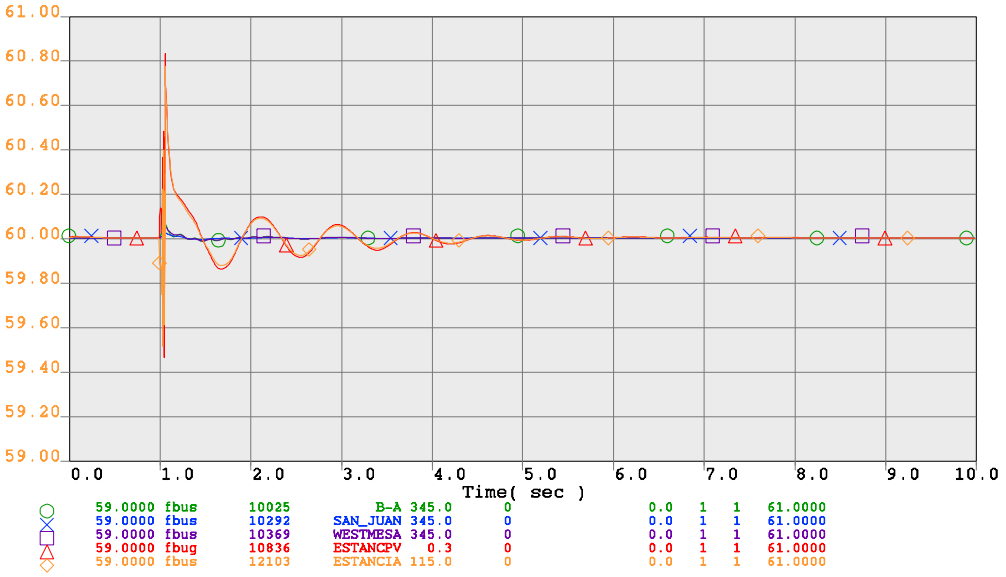
Page 1

120_hs_sav_post_WillEst.chf

Tue Sep 25 16:37:40 2012

Figure B-8--2016 HS----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to WILLARD 115 kV line--Voltage Plots





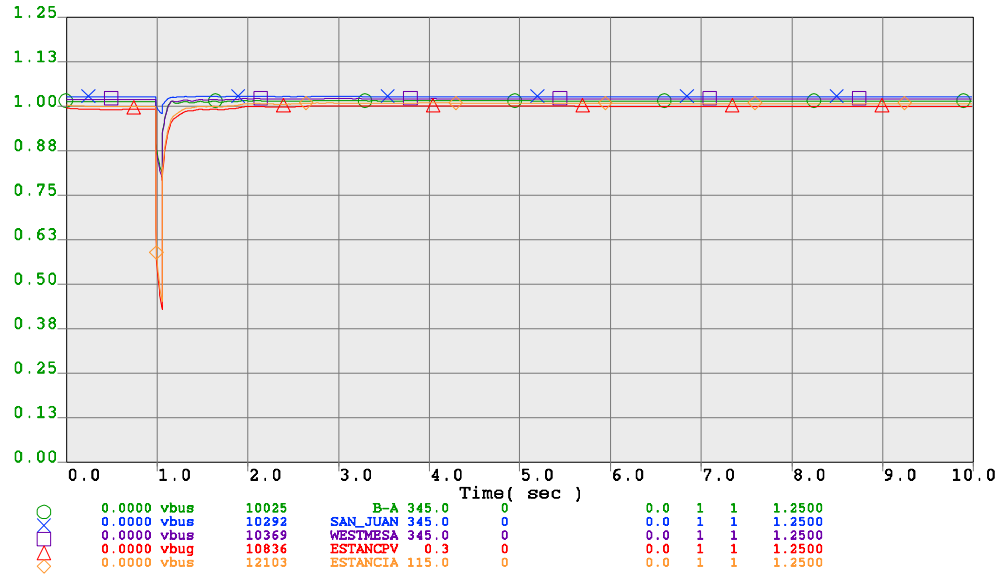
TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at BELEN 115 kV bus;
Trip BELEN_PG-TOME AND BELEN_PG 115 kV Lines in 4 cycles.

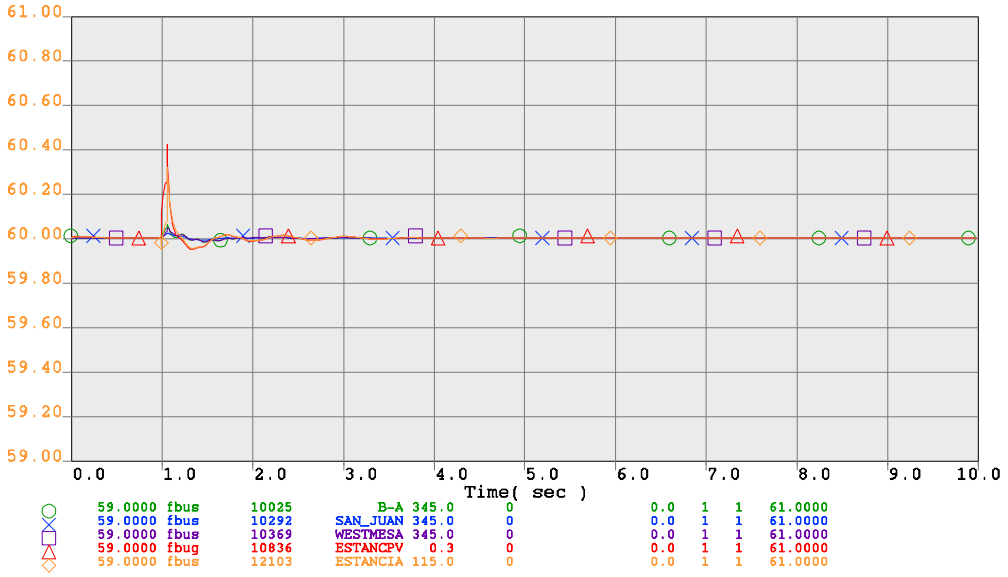
Page 1

120_hs_sav_post_BELTOMEWILL.chf

Tue Sep 25 10:21:08 2012

Figure B-9--2016 HS----3 Phase Fault at BELEN 115 kV; Open BELEN to TOME AND BELEN to WILLARD 115 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME Line TOME 115/46 kV transformer in 4 cycles.

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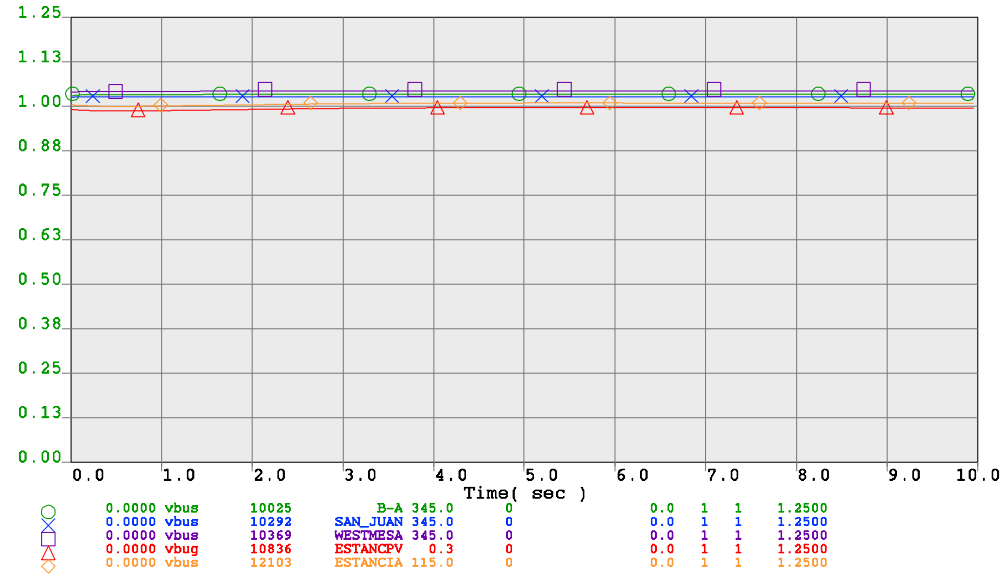
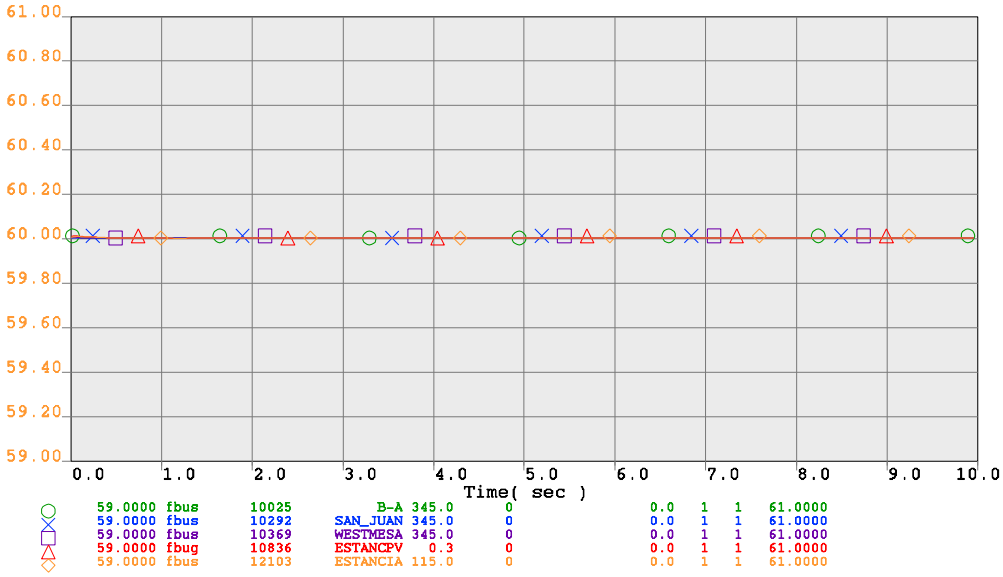
120_hs_sav_post_BELTOMETOMEXFMR.chf

Tue Sep 25 10:21:15 2012

Figure B-10--2016 HS----3 Phase Fault at TOME 115 kV; Open BELEN to TOME AND TOME 115/46 kV transformer--Voltage Plots





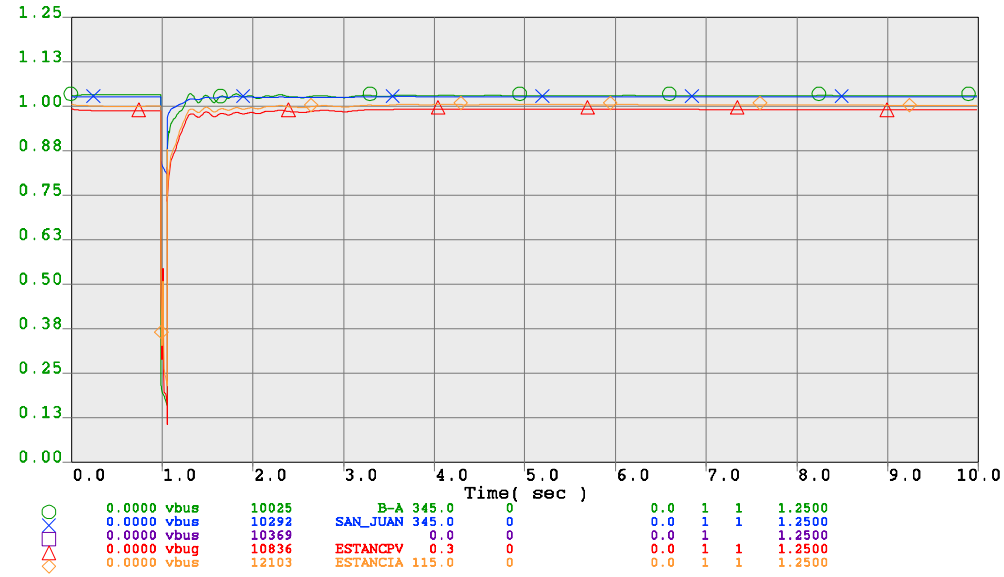
TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
No Disturbance

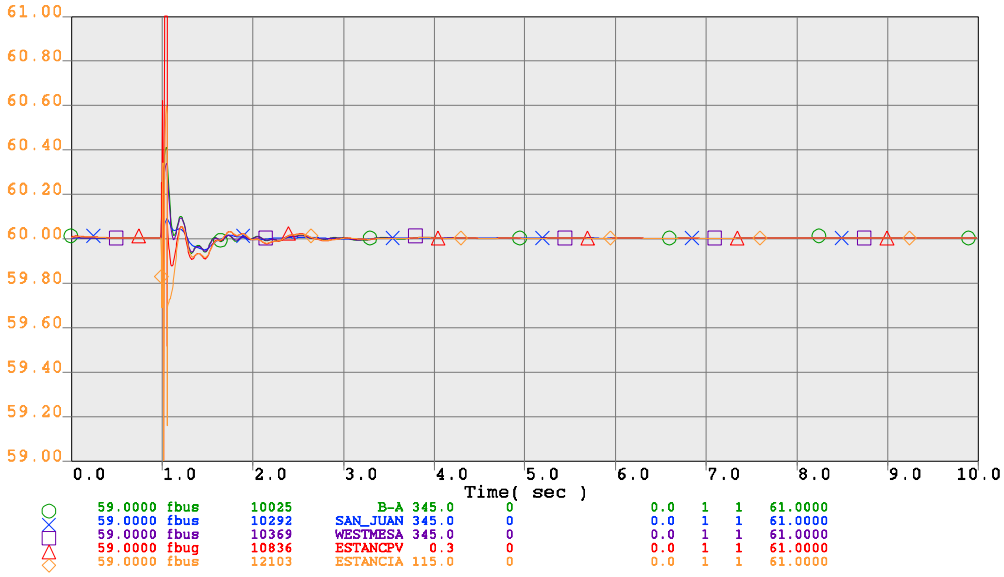
Page 1

nodisturbl20posthw.chf

Tue Sep 25 10:28:58 2012

Figure B-11--2015 HW----No Disturbance--Voltage and Frequency Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at West Mesa 345 kV bus;
Trip West Mesa-Arroyo in 4 cycles.

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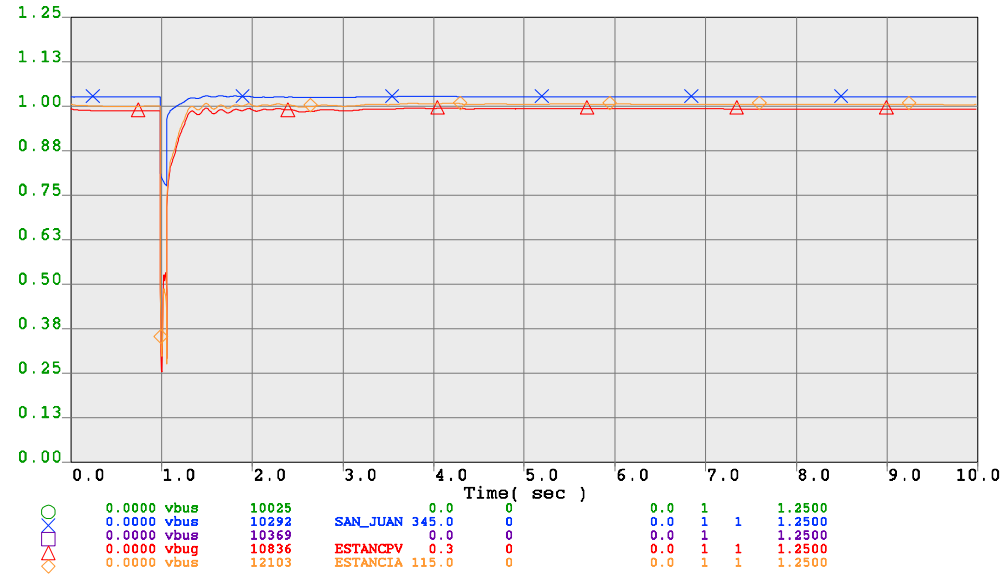
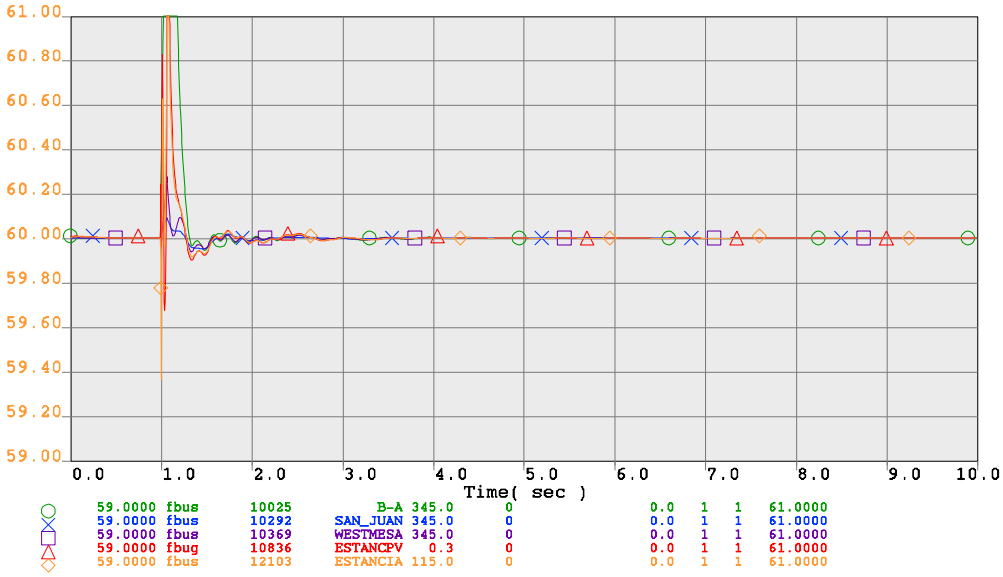
120_hw_sav_post_EP.chf

Tue Sep 25 10:29:43 2012

Figure B-12--2015 HW----3 Phase Fault at West Mesa 345 kV; Open West Mesa to Arroyo 345 kV line--Voltage and Frequency Plots





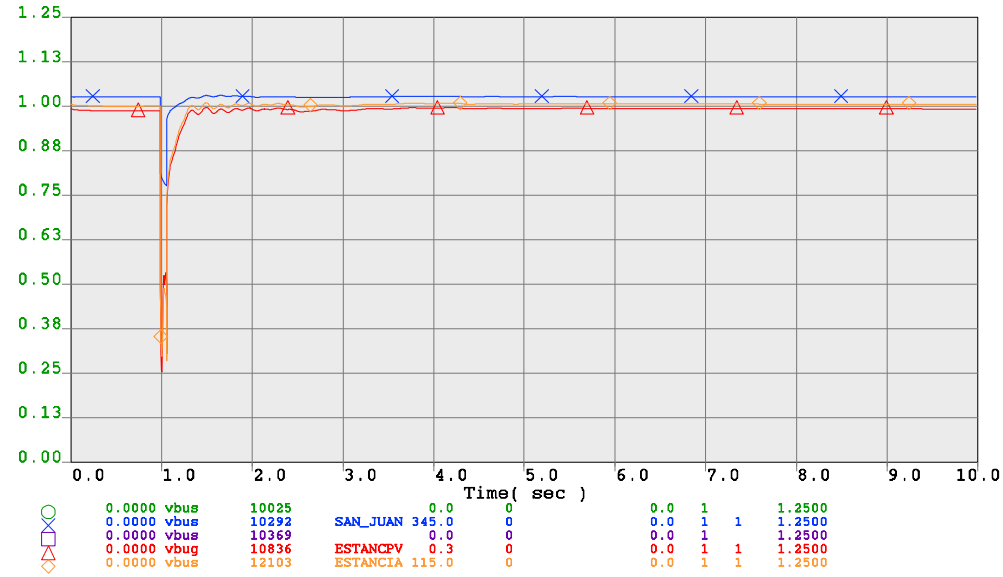
TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at Rio Puerco 345 kV bus;
Trip Rio Puerco-West Mesa 345 kV Line in 4 cycles.

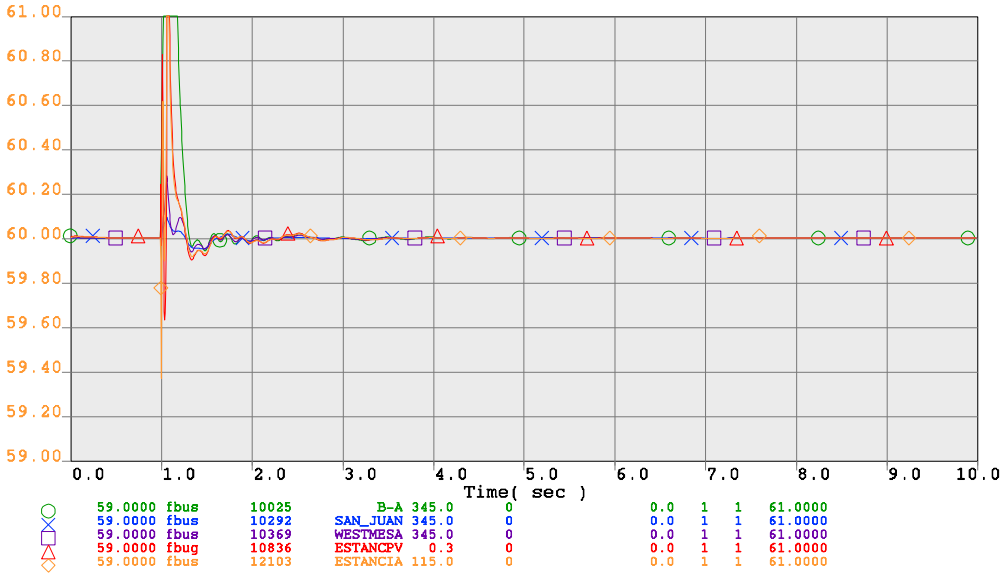
Page 1

120_hw_sav_post_RPWM.chf

Tue Sep 25 10:29:04 2012

Figure B-13--2015 HW----3 Phase Fault at Rio Puerc 345 kV; Open Rio Puerco to West Mesa 345 kV line--Voltage Plots





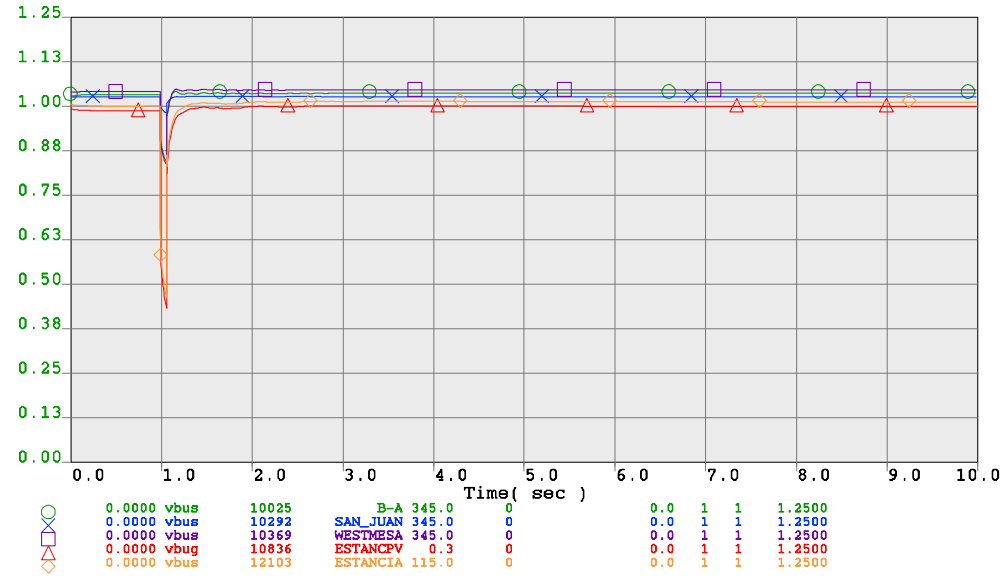
TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at BA 345 kV bus;
Trip Rio Puerco-BA 345 kV Line in 4 cycles.

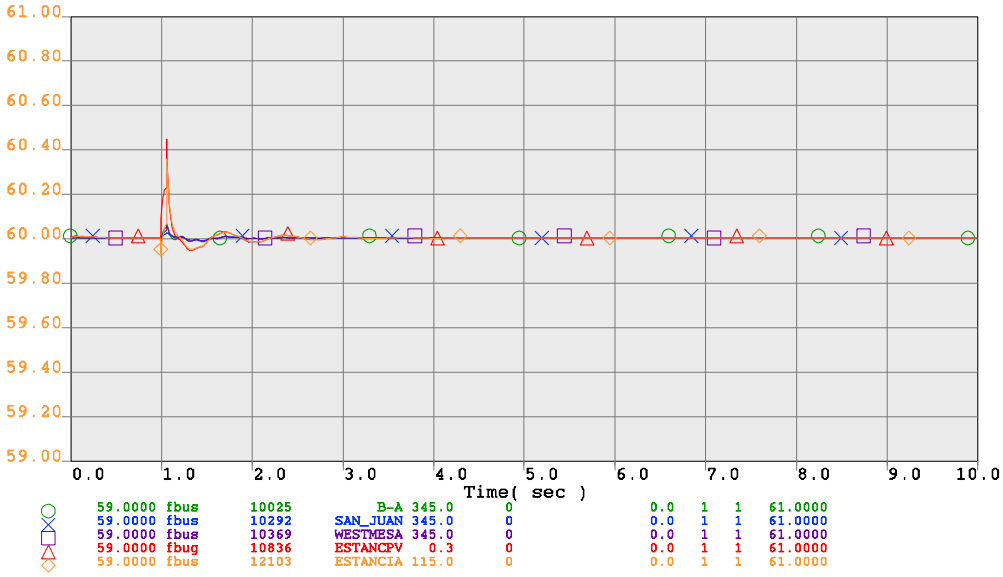
Page 1

120_hw_sav_post_RPBA.chf

Tue Sep 25 10:29:10 2012

Figure B-14--2015 HW----3 Phase Fault at BA 345 kV; Open Rio Puerco to BA 345 kV line--Voltage Plots





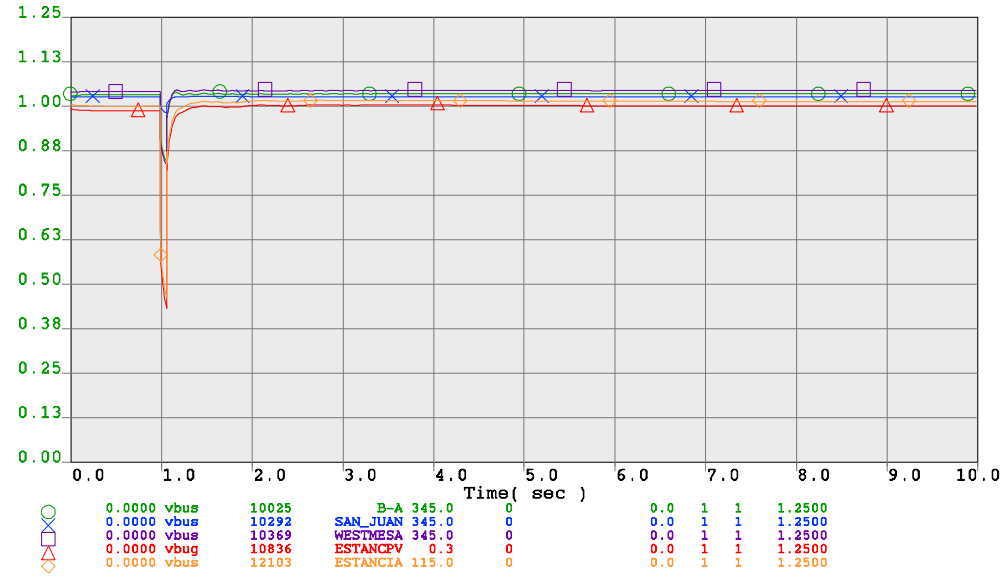
TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at TOME 115 kV bus;
Trip PERSON-TOME 115 kV Line in 4 cycles.

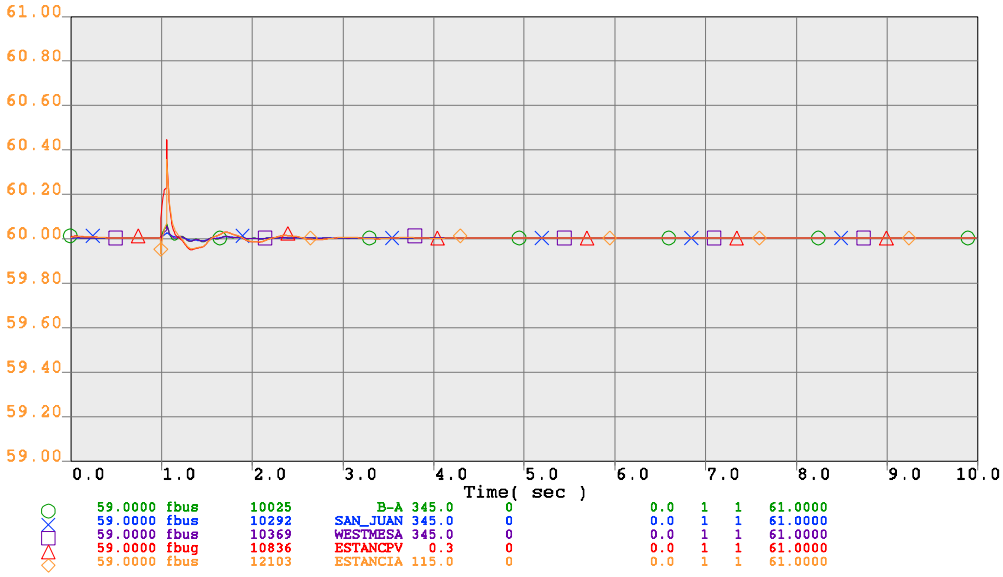
Page 1

120_hw_sav_post_PERTOME.chf

Tue Sep 25 10:29:23 2012

Figure B-15--2015 HW----3 Phase Fault at TOME 115 kV; Open PERSON to TOME 115 kV line--Voltage Plots





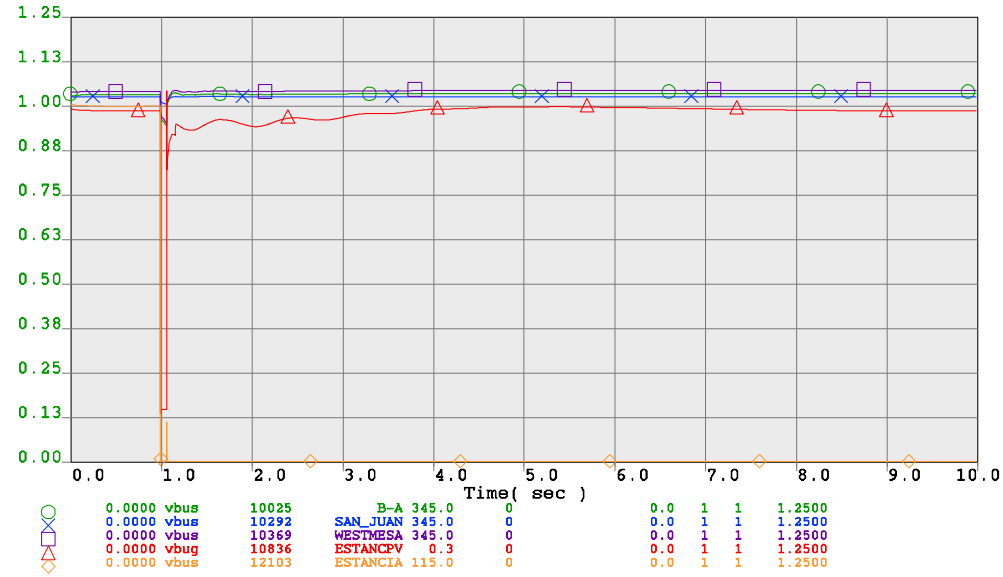
TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME 115 kV Line in 4 cycles.

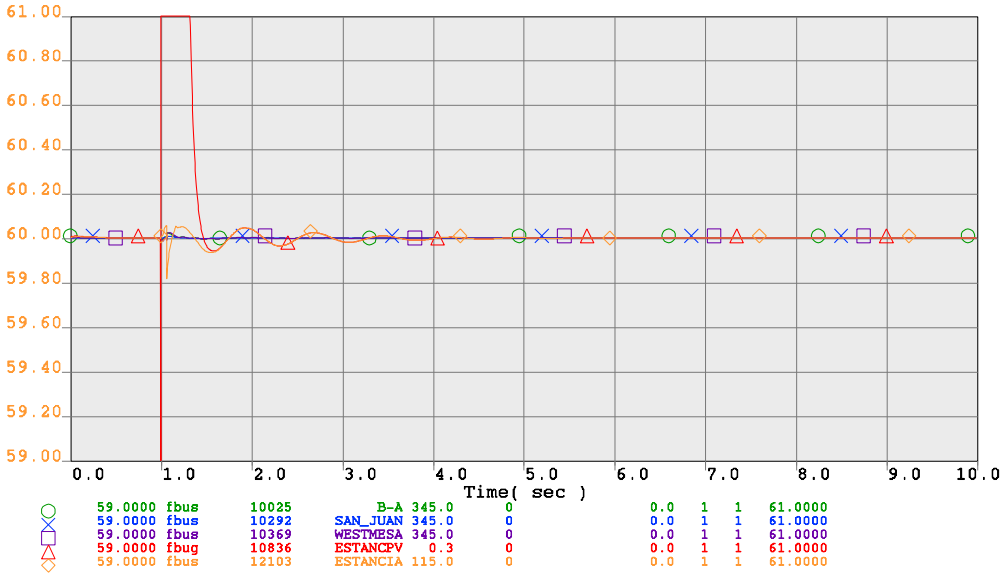
Page 1

120_hw_sav_post_BELTOME.chf

Tue Sep 25 10:29:17 2012

Figure B-6--2015 HW----3 Phase Fault at TOME 115 kV; Open BELEN to TOME 115 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to TORRANCE_PNM 115 kV line in 4 cycles.

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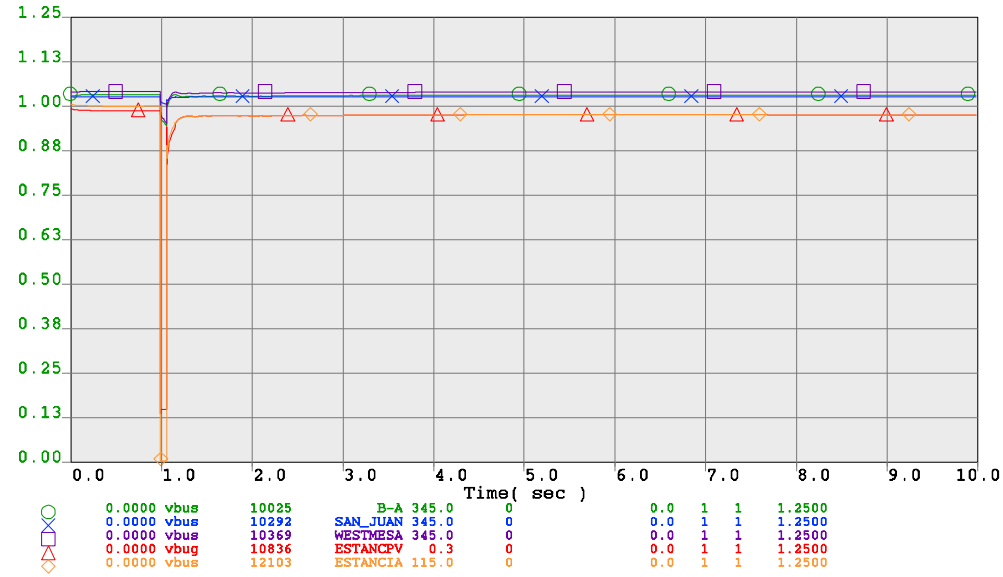
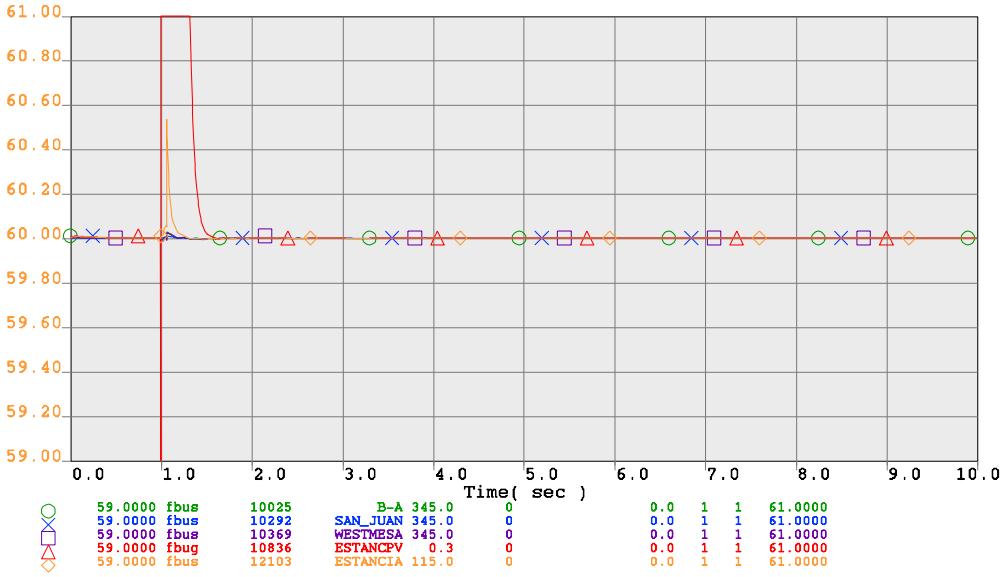
120_hw_sav_post_TorrEst.chf

Tue Sep 25 16:38:00 2012

Figure B-17--2015 HW----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to Britton 115 kV line--Voltage Plots





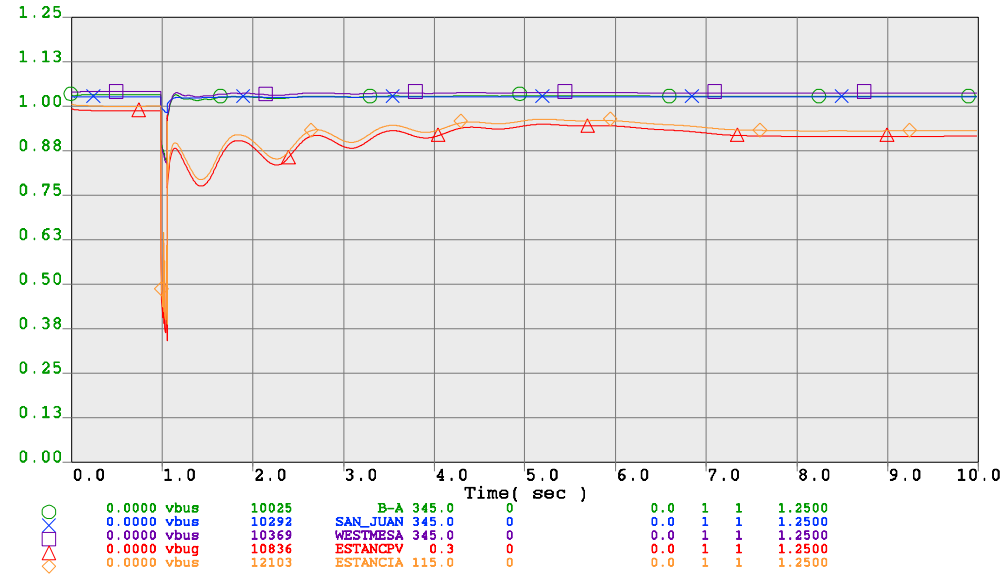
TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to WILLARD 115 kV line in 4 cycles.

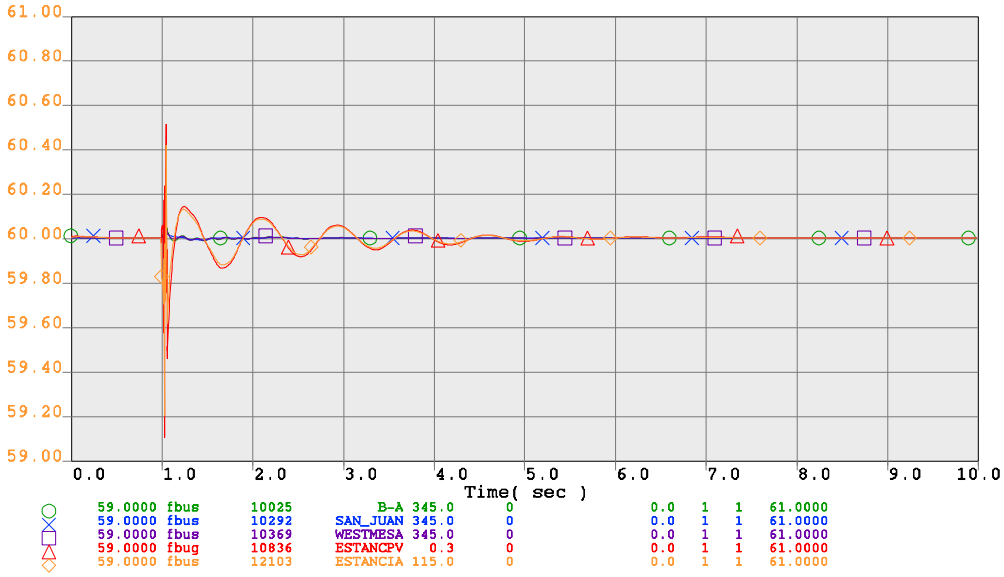
Page 1

120_hw_sav_post_WillEst.chf

Tue Sep 25 16:37:53 2012

Figure B-18--2015 HW----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to WILLARD 115 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at BELEN 115 kV bus;
Trip BELEN_PG-TOME AND BELEN_PG 115 kV Lines in 4 cycles.

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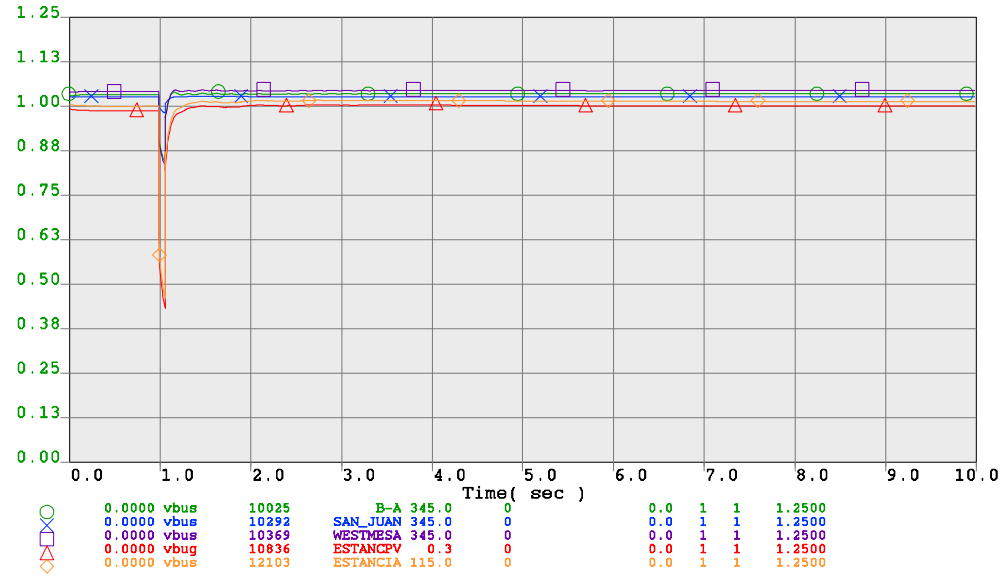
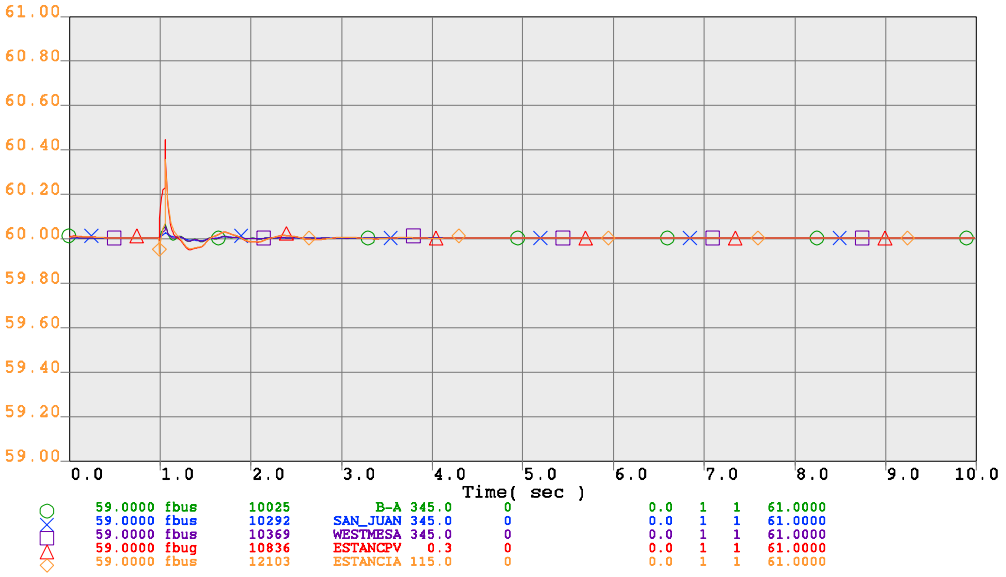
120_hw_sav_post_BELTOMEWILL.chf

Tue Sep 25 10:29:30 2012

Figure B-19--2015 HW----3 Phase Fault at BELEN 115 kV; Open BELEN to TOME AND BELEN to WILLARD 115 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME Line TOME 115/46 kV transformer in 4 cycles.

Page 1

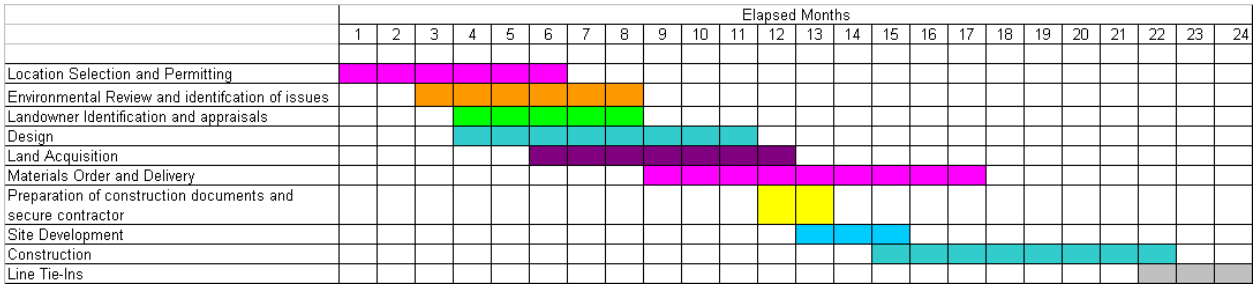
120_hw_sav_post_BELTOMETOMEXFMR.chf

Tue Sep 25 10:29:36 2012

Figure B-20--2015 HW----3 Phase Fault at TOME 115 kV; Open BELEN to TOME AND TOME 115/46 kV transformer--Voltage Plots

14. APPENDIX C: Construction Schedule and Assumptions

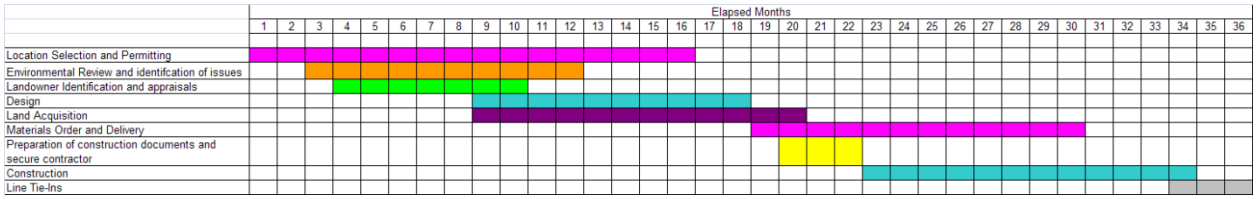
Estimated Station Construction Activity Schedule and Assumptions



Key assumptions:

- **PNM may elect to contract any or all parts of the project.**
- **Environmental estimate based on no significant environmental findings.**
- **Outage coordination for work on and under the AW line or other outages on the system may increase the schedule.**
- **Outages may be restricted to off-peak periods such as spring or fall.**
- **The project schedule is based on having all permits, agreements, and authorizations completed prior to initiation of construction work.**
- **General station pricing based on current equipment standards and standard station design.**
- **Right of Way pricing based on average acre values.**
- **Station design based on 500' x 700' site.**

Estimated Line Construction Activity Schedule and Assumptions



Key assumptions:

- **New line will be constructed using PNM's standard conductor (ACSR 795 Drake) and, subject to design review, will use standard steel poles.**
- **The rating of the line will be 200 MVA.**
- **Estimate assumes new right-of-way is acquired, including permitting.**
- **The final design of this line will evaluate alternate routes.**
- **PNM may elect to contract any or all parts of the project.**

- **The project schedule is based on having all permits, agreements, and authorizations completed prior to initiation of construction work.**
- **No major government permitting or environmental issues are encountered.**
- **A new line (approximately 17 miles) will be built paralleling the existing Algodones-Willard line.**
- **Right-of-way costs will be dependent on several factors including number of owners, owners' willingness to provide land or easement, and the width of needed easement, etc. Where reasonable, PNM will consider utilizing public rights-of-way. Direct purchase of land is estimated at fair market value.**

Small Generator Interconnection System Impact Study

For

XXX
20 MW Solar PV Generating Facility
SGI-PNM-2010-02
(Revised)

Date: 12/18/2012

Prepared by Public Service Company of New Mexico

Foreword

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Albuquerque, NM 87107

Table of Contents

1. EXECUTIVE SUMMARY

On January 25, 2010, XXX ("Interconnection Customer") perfected a Small Generator Interconnection ("SGI") request to interconnect a new 20 MW solar Photo Voltaic ("PV") plant near Estancia, New Mexico ("Project"). The proposed Point of Interconnection ("POI") is just south of the existing Tri-State Generation and Transmission ("Tri-State") Estancia 115 kV distribution substation as shown in Figure 1 below.

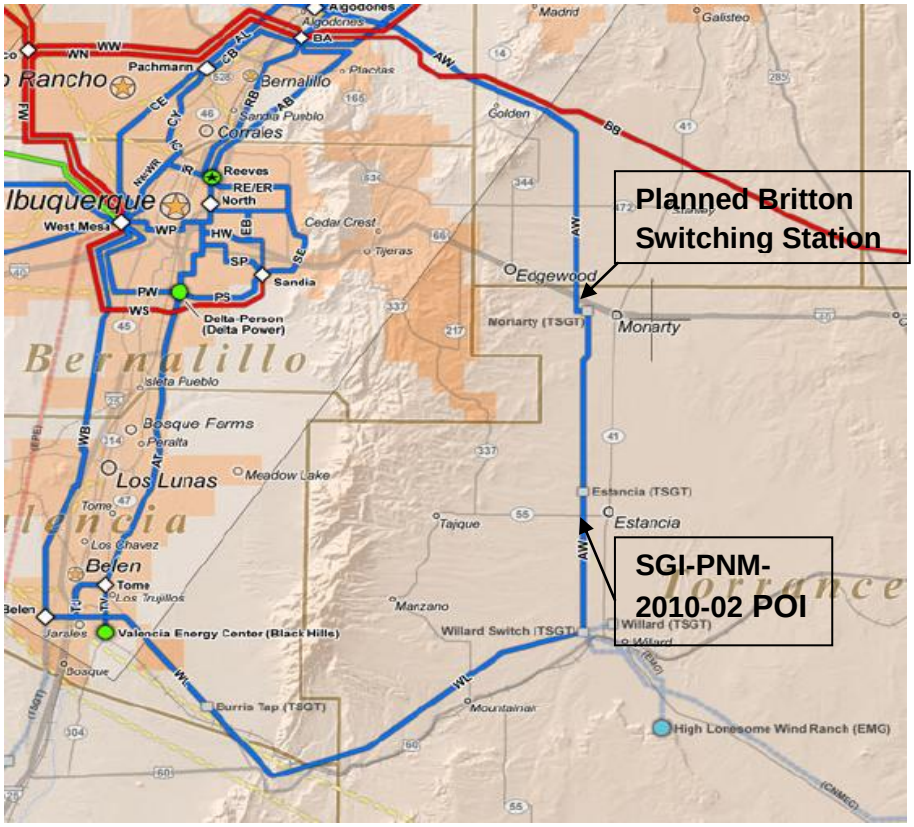


Figure 1

In response to the Interconnection Customer's request, PNM Transmission/Distribution Planning and Contracts performed an Interconnection System Impact Study ("Study") based on the assumptions, criteria and methodologies described below. The Study provided non-binding cost and construction schedule estimates for all identified system reinforcements required for interconnection at the POI.

The findings of the Study are summarized as follows:

Steady-State Performance

The powerflow analysis shows the following Network Upgrades are required to accommodate the interconnection for SGI-PNM-2010-02:

- Construction of a new three (3) terminal 115 kV ring bus switching station (expandable to a breaker and half scheme) just south of the Tri-State owned Estancia distribution substation on the Willard–Britton 115 kV line section of the Willard-Algodones 115 kV line.

Transmission service is not considered in this Study. This will be evaluated when specific point-to-point transmission delivery service is requested for the Project. This Study is not intended to imply any right to receive transmission service from PNM until such request is made.

A transmission service sensitivity is included in the body of the report assuming output of the facility is additive to existing PNM transmission service obligations out of the Willard area. This sensitivity is provided for informational purposes only.

POI Reactive Power Analysis

The reactive power analysis indicates reactive power capability of the Project is adequate to achieve a +/- 0.95 net power factor range at the POI.

It should be noted that the simplified equivalent collector system provided by the Interconnection Customers for the solar facilities do not allow for a detailed evaluation of reactive requirements from each individual solar panel to the POI. This analysis only provides an indication of reactive power requirements and it remains the Interconnection Customer's responsibility to design their generation facilities and additional supplemental reactive support to meet the requirements at the POI.

Conclusion

The cost estimate and schedule for the necessary Network Upgrades for SGI-PNM-2010-02 are summarized below:

Upgrades Required		
System Upgrade	**Project Costs ($M)**	**Construction Time**
Construct a new three (3) breaker 115 kV switching station at POI just south of Estancia	6	24 months
Total	**6**	**24 months**

2. INTRODUCTION

On January 25, 2010, XXX ("Interconnection Customer") perfected a Small Generator Interconnection ("SGI") request to interconnect a new 20 MW solar PV plant near Estancia, New Mexico ("Project"). The proposed Point of Interconnection ("POI") is just south of the existing Tri-State Generation and Transmission ("Tri-State") Estancia 115 kV distribution substation. The Project interconnection to the PNM transmission system is shown in Figure 2.

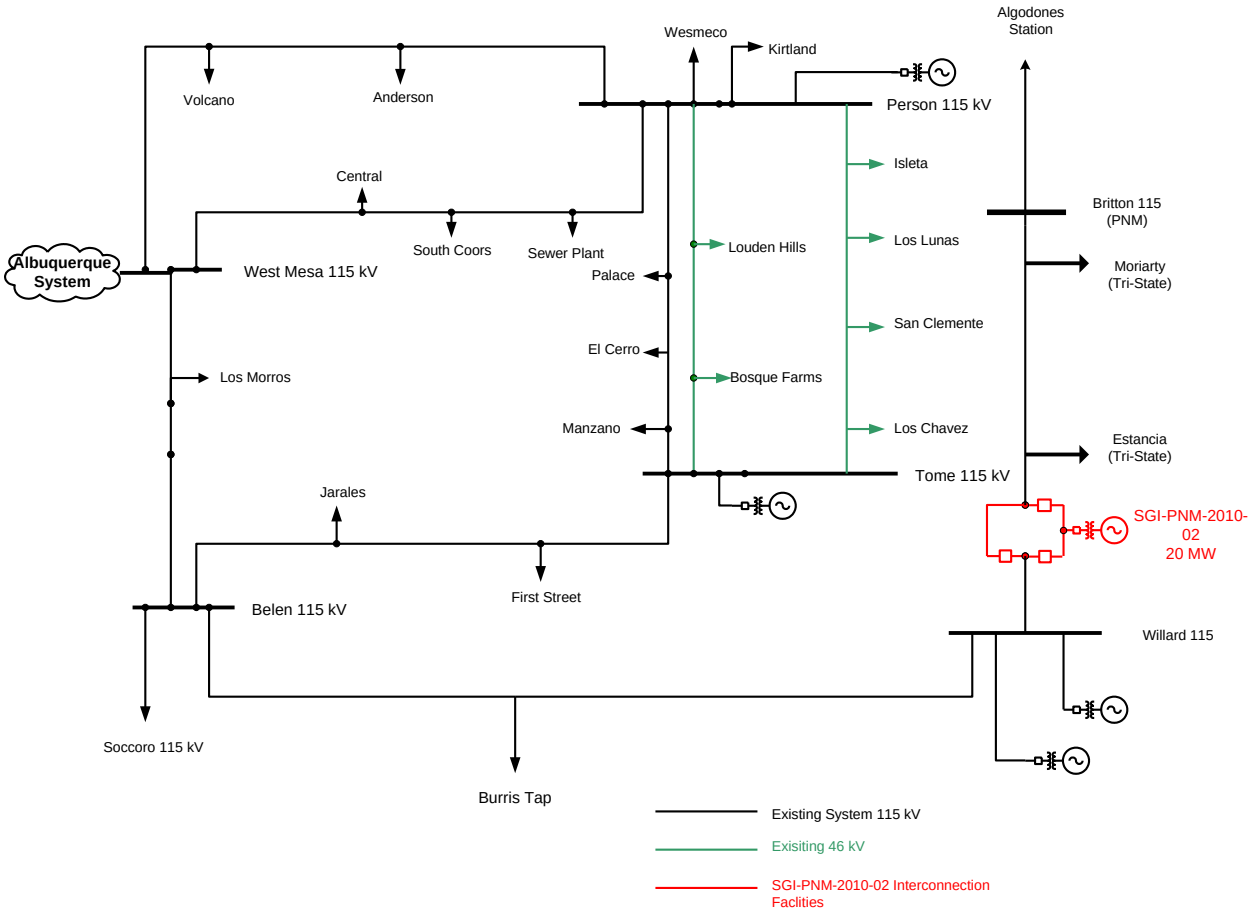


Figure 2

In response to the Interconnection Customer's request, PNM Transmission & Distribution Planning and Contracts will perform an Interconnection System Impact Study ("Study") based on the assumptions, criteria and methodologies described below. The Study also provides non-binding cost and construction schedule estimates for all identified system reinforcements required for interconnection at the POI.

3. STUDY CRITERIA

3.1 Thermal and Voltage Criteria

The steady-state performance criteria applicable to powerflow analysis in the Study are shown in Table 1. The criteria are NERC/WECC performance requirements as well as applicable additions and exceptions for the New Mexico transmission system.

Table 1. Powerflow Performance Criteria

Area	Conditions	Loading Limits	Voltage (p.u.)	Voltage Drop	Application
EPEC (Area 11)	Normal	< Normal Rating	0.95 - 1.05		69kV and above
			0.95 - 1.07		Artesia 345 kV
			0.95 - 1.08		Arroyo 345 kV PST source side
			0.90 - 1.05		Alamo, Sierra Blanca and Van Horn 69kV
	Contingency	< Emergency Rating	0.925 - 1.05	7%	60 kV to 115 kV
			0.95 - 1.07	7%	Artesia 345kV
			0.95 - 1.08	7%	Arroyo 345kV PST source side
			0.90 - 1.05		Alamo, Sierra Blanca and Van Horn 69kV
			0.95 - 1.05	7%	Other 345 kV buses
PNM (Area 10)	Normal ALIS	< Normal Rating	0.95-1.05		46 kV and above*
	Contingency N-1	< Emergency Rating	0.925 - 1.08^	6 %**	46 kV to 115 kV
			0.90 – 1.08^	6 %**	230 kV and above
	Contingency N-2	< Emergency Rating	0.90 - 1.08^	10 %	46 kV and above*
Tri- State (zones 120-123)	Normal ALIS	< Normal Rating	0.95-1.05		All buses
	Contingency N-1	< Emergency Rating	0.90-1.1	6 %***	69 kV and above except Northeastern NM and Southern NM
			0.90-1.1	7 %***	69 kV and above in Northeastern NM and Southern NM
	Contingency N-2	< Emergency Rating	0.90-1.1	10%	All buses

*Taiban Mesa and Guadalupe 345 kV voltage 0.95 and 1.1 p.u. under normal and contingency conditions.
**For PNM buses in southern New Mexico (Zones 104,130, 131, and 132), the allowable N-1 voltage drop is 7%.
*** Tri-State Voltage Criteria, April 2008.
^ Provided operator action can be utilized to adjust voltages at or below 1.05 pu

3.2 Generator Reactive Power Range Criteria

The procedure used for evaluating the reactive power requirements is contained in PNM's interconnection requirements for generators.[1] In this approach, a power flow simulation is conducted both with and without the Project generation enabled on the post-project base case. The Project-enabled case represents the reactive power range at full output and control capability described in the interconnection application. The power flow simulation is conducted to determine whether voltage at the POI or adjacent transmission nodes differs by more than 1.0% for normal or contingency conditions without other generators in the area regulating voltage. These units can be taken off line if necessary when performing this evaluation. If it does, then supplemental reactive power support to achieve a +/- 0.95 power factor range at the POI shall be required.

3.3 Transient Stability Performance Standard

The NERC/WECC transient stability performance requirements for transmission contingencies are as follows:

- All machines will remain in synchronism.

[1] See PNM FAC-001-R2.1.3 - VOLTAGE LEVEL AND MW/MVAR CAPACITY OR DEMAND.

- All voltage swings will be well damped.
- Following fault clearing for single contingencies, voltage on load buses may not dip more than 25% of the pre-fault voltage or dip more than 20% of the pre-fault voltage for more than 20 cycles. For N-2 and breaker failure contingencies, voltage on load buses may not dip more than 30% of the pre-fault voltage or dip more than 20% of the pre-fault voltage for more than 40 cycles.

Table 2—PNM Fault Clearing Times

Fault Type	Voltage (kV)	Clearing Time (near-far end breakers—see note below)
3 Phase Normally Cleared	345	4–4 Cycles
	230	4–4 Cycles
	115	4–4 Cycles
Fault Type	**Voltage (kV)**	Clearing Time (normally opened breaker both near and far end—breaker opened due to stuck breaker both near and far end
1 Phase* Stuck Breaker	345	4-12 Cycles
	230	
	115	4-15 Cycles

3.4 Voltage Ride-Through Requirement

Generators connected to the PNM transmission system are required to meet the voltage ride-through requirements contained in PRC-024-WECC-CRT-0-Low Voltage Ride Through Criterion[2]. In this case, SGI-PNM-2010-02 is expected to ride through (i) three-phase faults, cleared in normal time and (ii) single-line-to-ground faults with delayed clearing at Estancia.

It should be noted that positive-sequence, reduced-order simulation models for PV plants do not allow for a detailed evaluation of voltage ride-through. The interconnection studies only provide an indication of risk, and it remains the Interconnection Customer's responsibility to design the Project to meet the ride-through requirement.

3.5 Interconnection Requirements

Consistent with FAC-001 R1.1, PNM's Interconnection Facilities will be designed to maintain the integrity of the existing PNM transmission equipment, provide for termination of the Interconnection Customer facilities while maintaining transmission maintenance flexibility, and provide protection of the PNM Transmission System from a failure within the Interconnection Customer facilities and risk associated with three terminal line protection. As a minimum, PNM requires a three-breaker ring bus configuration for a single generation interconnection to the Bulk Electric System.

[2] http://www.wecc.biz/library/Documentation Categorization Files/Regional Criteria/PRC-024-WECC-CRT-0 Low Voltage Ride Through Criterion Effective Date 4-8-2005.pdf

4. BASE CASE DEVELOPMENT

A WECC 2016 heavy (peak load) summer case (2016hs2) and 2015 heavy winter case (2015-16 HW2A) were used to develop the base cases. Generation dispatch and generation displacement modifications were added as discussed below.

4.1 Generation Dispatch

Proposed generation projects in the Project area holding a senior position in PNM's generator interconnection queue and their respective transmission system reinforcements are included in the base cases. Certain existing or proposed projects outside the Project area which do not have an impact on the Project are excluded or were not dispatched. Table 3 shows the generation pattern for existing and proposed generation projects.

Table 3 – Generation Dispatch

Unit	Nameplate Rating	Summer Peak Output Level*	Winter Output Level*
Four Corners Unit 1	192	0	0
Four Corners Unit 2	192	0	0
Four Corners Unit 3	256	0	0
Existing Reeves 1	43	0	0
Existing Reeves 2	44	0	0
Existing Reeves 3	66	0	0
Existing Delta-Person	132	0	0
Existing Valencia Energy Facility	143	143	0
Existing Taiban Mesa Wind Project	200	200	200
Existing Aragonne Mesa Wind Project	90	90	90
Existing Red Mesa Wind Project	100	100*	100*
Existing High Lonesome Mesa Project	100	100	100
Proposed Taiban Mesa II Project	50	50	50
Proposed Torrance Biomass Project	37.5	37.5*	37.5*
Proposed Granada Wind Project	300	300	300
Proposed Arabella Solar Project	300	0**	0**
Proposed Delta-Person Expansion	90	0	0
Proposed La Sierrita Wind Farm	70	0**	0**
Proposed Reeves Repower Project	140	0	0
Proposed Pajarito Project	176	0	0
Proposed El Cabo Wind	300	0**	0**
Proposed Mountainair Wind Project	100	0**	0**
Proposed Dunmoor Wind	700	0**	0**

*Output considered at 0 for interconnection only assessment.

**Energy Resource – set to 0 since output will be curtailed if system improvements are required.

Blackwater is scheduled at 50 MW west in both on and off peak powerflow cases.

In the heavy summer base case, the pre-Project case has a Southern New Mexico Import (SNMI) level of approximately 265 MW while the Northern New Mexico Import (NNMI) level is approximately 900 MW. The Arroyo Phase Shifting Transformer (PST) is scheduled at 60 MW southbound. The Blackwater HVDC converter is scheduled at 50 MW westbound.

In the winter base case, the pre-Project case has an SNMI level of approximately 430 MW, while the NNMI level is approximately 740 MW. The Arroyo Phase Shifting Transformer (PST) is scheduled at approximately 200 MW southbound. The Blackwater HVDC converter is scheduled at 50 MW Westbound.

Key transmission assumptions include:

- A Gallup to PEGS 115 kV line rating of 96 MVA.
- A second Springer – Gladstone 115 kV line with a rating of 169 MVA.
- A Springer – Storrie Lake 115 kV line rating of 102 MVA.
- The Rio Puerco Phase III transmission project in service.
- A Clapham – Rosebud 115 kV line rating of 169 MVA.

Key resource related assumptions included:

- Retiring Four Corners Units 1, 2 and 3 and displacing the output with other Arizona resources.
- Adjusting Arizona resources to offset output of senior queued interconnection projects in New Mexico.
- Adjusting Arizona resources to offset output of resources associated with transmission service requests.
- Dispatching the TA-3 15 MW and 20 MW units to serve projected Los Alamos load.
- Setting the planned Gladstone 230 kV phase shifting transformer to hold a 150 MW north to south schedule.

The following senior queued interconnection projects on third party transmission systems are modeled:

- TI-04-1214[3] Wind project generating 88 MW
- Cimarron PV Solar facility generating 16.8 MW

[3] http://www.tristategt.org/OASIS/documents/TI-04-1214 SIS Final Report_RAL3.pdf

The following Transmission Service Requests are modeled

- TSR 73152312 (80 MW) – Ojo 345 kV to Four Corners 345 kV
- TSR 74116380 (20 MW) – Ojo 345 kV to Four Corners 345 kV
- TSR 71452501 (50 MW) – Blackwater 230 kV to Four Corners 345 kV
- TSR 73140963 (90 MW) – Willard 115 kV to Four Corners 345 kV
- TSR 73140972 (10 MW) – Willard 115 kV to Four Corners 345 kV
- TSR 71639149 (90 MW) – Guadalupe 345 kV to Four Corners 345 kV
- TSR 74559236 (102 MW) – Red Mesa 115 kV to Four Corners 345 kV
- TSR 76410780 (37 MW) – Willard 115 kV to Four Corners 345 kV
- TSR 74623905 (300 MW) – Guadalupe 345 kV to Four Corners 345 kV

4.2 Project Data

The corresponding equivalent representations for the Project parameters are listed below and reflect data provided by the Interconnection Customer.

Interconnection Transmission Line:

Distance: 500 feet
Voltage: 115 kV
Positive sequence impedance on 100 MVA base:
R = 0.0002482 p.u. X = 0.00054175 p.u. B = 0.0000704692 p.u.
Zero sequence impedance on 100 MVA base:
R = 0.00047718 p.u. X = 0.0020059 p.u.

Generator Data:

Nameplate rating:	0.5 MW (40 inverters)
Reactive:	+/- .90 power factor controlled
Terminal voltage:	.270 kV

Generator Pad Mounted Transformer Configuration:

Rating:	25 MVA (20 pad-mounted at 1.25 MVA each)
Voltage Ratio	34.5 kV/0.270 kV
Impedance	R= 0.0030 p.u., X= .0750 p.u. on 25 MVA base

Collector System Impedance on 100 MVA base:

R = .002758 p.u. X = 0.00507355 p.u. B = 0.00000759 p.u.

Station Step-Up Transformer Configuration:

Rating:	(ONAN/FA/FA): 18/24/32 MVA

Voltage Ratio	34.5/115/13.8 kV
Impedance	R = 0.00258 p.u., X = 0.0956 p.u., 18 MVA base

5. LIST OF CONTINGENCIES

The power flow contingencies evaluated in this study are listed in Table 4 and Table 5 below.

Table 4 - List of N-1 Contingencies

N-1 Contingencies	Pre-Project	Post-Project
FOUR CORNERS-RIO PUERCO	X	X
SAN JUAN-RIO PUERCO 345	X	X
WESTMESA-SANDIA 345	X	X
BA-NORTON 345	X	X
RIO PUERCO-WESTMESA 345	X	X
RIO PUERCO-BA 345	X	X
WESTMESA-ARROYO PS 345	X	X
RIOPUERCO 345/115 XFMR	X	X
ALGODONES-PACHMANN 115	X	X
BA-REEVES1 115	X	X
BA-REEVES2 115	X	X
BA-PACHMANN 115	X	X
CORRALES-PACHMANN 115	X	X
PERSON-TOME 115	X	X
BELEN-TOME 115	X	X
BRITTON-WILLARD 115	X	
ALGODONES-BRITTON 115	X	X
BRITTON-ESTANCIA 115		X
WILLARD-ESTANCIA 115		X
WEST MESA 3-BELEN 115	X	X
BELEN-WILLARD 115	X	X
FOUR CORNERS-SAN JUAN 345	X	X
FOUR CORNERS-SHIPROCK 345	X	X
SAN JUAN-SHIPROCK 345 kV	X	X
SOCORRO-BELEN_PG 115	X	X
SGI-PNM-2010-02		X

Table 5 - List of N-2 and Breaker Failure Contingencies

N-2 Contingencies	Pre-Project	Post-Project
RIO PUERCO-BA 1&2 345	X	X
ALGODONES-PACHMANN-BA 115	X	X
ALGODONES-PACHMANN-WESTMESA 115	X	X
BELEN-TOME & BELEN-WILLARD 115	X	X

Lists of the N-1 and N-2 contingencies evaluated for system stability are provided in Table 6 and Table 7, respectively.

Table 6– N-1 Contingencies

Disturbance Case #	Disturbance	Fault Location	Fault Type
1	WESTMESA-ARROYO PS 345	WEST MESA 345	3-Phase
2	RIO PUERCO-WESTMESA 345	RIO PUERCO 345	3-Phase
3	RIO PUERCO-BA 345	BA 345	3-Phase
4	PERSON-TOME 115	TOME 115	3-Phase
5	BELEN-TOME 115	TOME 115	3-Phase
6	ESTANCIA-BRITTON 115	ESTANCIA 115	3-Phase
7	ESTANCIA-WILLARD 115	ESTANCIA 115	3-Phase

Table 7 – N-2 Contingencies

Disturbance Case #	Disturbance	Fault Location	Fault Type
8	BELEN-TOME & BELEN-WILLARD 115	BELEN 115	3-Phase
9	BELEN-TOME 115 + TOME 115/46 XFMR	TOME 115	3-Phase

6. REACTIVE POWER ANALYSIS

To assess reactive power requirements, a power flow simulation is conducted both with and without the Project generation in service. The cases with generation in service model the reactive power range of each respective generator and the control capability as specified by the customer in the interconnection application. The power flow simulation is conducted to determine whether voltage at the POI or adjacent transmission nodes differs by more than 1.0% for normal or contingency conditions. If it does, then supplemental reactive power support to achieve a +/- 0.95 power factor range at the POI shall be required if the reactive capability specified by the customer does not meet this range.

The results of this analysis under contingency conditions are shown in Table 8 using the reactive capability of the projects as provided by the customers. For both the heavy summer

and heavy winter cases, the voltage change at the POI under contingency conditions meets or exceeds the 1.0% voltage change criteria.

Powerflow results modeling the reactive capability of the Project indicate sufficient reactive range to meet +/- .95 requirements at the POI.

Table 8. Voltage Change Analysis at the POI

Bus	Contingency	Pre-Project HS	Post-Project HS	Post - Pre % HS Voltage Change
ESTANCIA 115 kV	BELEN-WILLARD 115 kV (WL)	0.961	0.996	3.64%
Bus	**Contingency**	**Pre-Project HW**	**Post-Project HW**	**Post - Pre % HW Voltage Change**
ESTANCIA 115 kV	BELEN-WILLARD 115 kV (WL)	0.991	1.01	1.92%

7. SGI INTERCONNECTION ANALYSIS

As an SGI interconnection request, the Project was analyzed in a similar manner to the Large Generation Interconnection Procedure (LGIP) request for energy resource interconnection service. Sufficient transmission capacity exists in the area of the Project for exporting up to 137 MW. This capacity has been committed under long term transmission service agreements to other customers, however, for assessment of the interconnection requirements existing capacity is assumed available. This limits the Network Upgrades required to accommodate the Project to the interconnection station at the POI. The estimated cost and schedule for the upgrades is summarized in Table 9.

8. COST AND CONSTRUCTION TIME ESTIMATES

Table 9. Upgrades Required

Upgrades Required		
System Upgrade	**Project Costs ($M)**	**Construction Time**
Construct a new three (3) breaker 115 kV switching station at POI just south of Estancia	6	24 months
Total	**6**	**24 months**

The following general assumptions apply to all PNM cost estimates and schedules:

1. For all estimates, pricing is based on 2012 unit costs. With likely fluctuations in the price of raw materials, fuel, and labor, actual costs may vary in future years.
2. Cost estimates are considered to be within +/- 20%.
3. Estimates include, rights-of-way, governmental permitting, design, materials, construction, construction management, and internal utility loads.
4. Project schedules are considered reasonably accurate but can be affected by permitting delays, equipment deliveries, weather, availability of workforce, and availability of outage clearance for construction.
5. The proposed schedule for final design and construction is estimated to take 24 months from an authorization to begin work.

9. FIRM TRANSMISSION SERVICE SENSITIVITY

This section identifies additional transmission improvements to provide firm transmission service assuming that the Project output is in addition to existing customer commitments out of the Willard area. This section is for informational purposes only.

9.1 Powerflow Analysis

Powerflow results show that for summer peak and winter peak conditions, the Project meets voltage performance criteria. Tables 10 and 11 show that there are line overloads from the POI (near Estancia 115 kV) to Moriarty 115 kV for the Belen-Willard 115 kV N-1 contingency. A rebuild of the existing line has been ruled out in previous study efforts due to reliability concerns associated with providing service to existing customers during construction. In order to mitigate this overload, a new 16.6 mile 115 kV transmission line will need to be constructed from the POI to the planned PNM Britton 115 kV switching station. These Network Upgrades are illustrated in Figure 3.

Table 10 Heavy Summer Contingency p.u. Loading (Based on emergency MVA rating)

Contingency	Monitored Element	MVA Rating Normal/Emergency	Pre-Project	Post-Project
N-1				
Belen-Willard 115 kV	Estancia-Moriarty 115 kV	120/130	<.95	1.064
Belen-Willard 115 kV	Estancpn-Estancia 115 kV	120/130	.976	1.131
N-2				
Willard-Belen-Tome 115 kV	Estancia-Moriarty 115 kV	120/130	<.95	1.064
Willard-Belen-Tome 115 kV	Estancpn - Estancia 115 kV	120/130	.976	1.131

Table 11 Heavy Winter Contingency p.u. Loading (Based on emegency MVA rating)

Contingency	Monitored Element	MVA Rating Normal/Emergency	Pre-Project	Post-Project
N-1				
Belen-Willard 115 kV	Estancia-Moriarty 115 kV	120/130	<.95	1.093
Belen-Willard 115 kV	Estancpn -Estancia 115 kV	120/130	.983	1.137
N-2				
Willard-Belen-Tome 115 kV	Estancia-Moriarty 115 kV	120/130	<.95	1.092
Willard-Belen-Tome 115 kV	Estancpn-Estancia 115 kV	120/130	.983	1.137

The N-2 overloads shown in Table 10 and Table 11 will be mitigated by the addition of the line between Estancia and Willard so additional mitigations for the N-2 contingencies are not required.

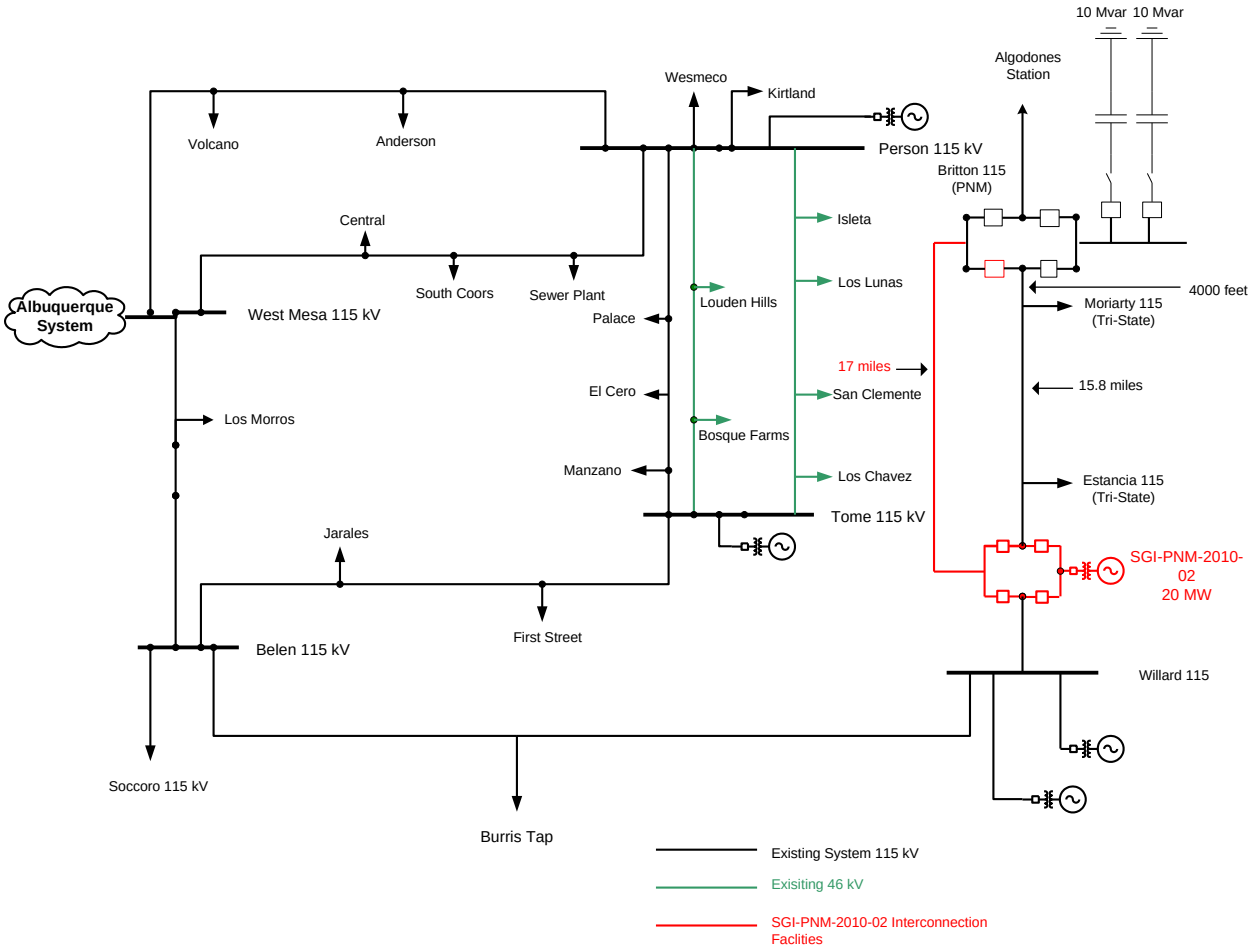


Figure 3

9.2 **Stability Analysis**

For the stability analysis, N-1 and N-2 contingencies were considered for both the heavy summer and light winter cases. For each of the cases, the Post-Project system response was found to be in compliance with transient stability criteria. Transient stability simulation plots are included in Appendix B.

The stability results also showed that the post-Project system met voltage-ride-through requirements. It should be noted that positive-sequence, reduced-order simulation models for PV plants do not allow for a detailed evaluation of voltage ride-through. The interconnection studies only provide an indication of risk, and it remains the Interconnection Customer's responsibility to design the Project to meet the ride-through requirement.

9.3 Short Circuit Analysis

Previous short circuit analysis for similar Projects located near Estancia have shown that this Project will not increase short-circuit duty at any existing stations beyond equipment ratings and, as a result, will not require additional network upgrades to insure facilities are adequate for expected worst case short circuit duty.

9.4 Cost and Construction Time Estimates

Table 12. Upgrades Required for Firm Transmission Service Sensitivity

System Upgrade	Project Costs ($M)	Construction Time
Expand the interconnection 115 kV switching station by adding one breaker	1	24 months
Expand the planned PNM Britton 115 kV switching station by adding one breaker	1	24 months
Construct a new 16.6 mile 115 kV transmission line (795 kcmil ACSR) from the interconnection 115 kV switching station at the POI to the planned PNM Britton 115 kV switching station.	9.96	36 months
Total	**11.96**	**36 months**

The following general assumptions apply to all PNM cost estimates and schedules:

6. For all estimates, pricing is based on 2012 unit costs. With likely fluctuations in the price of raw materials, fuel, and labor, actual costs may vary in future years.
7. Cost estimates are considered to be within +/- 20%.
8. Estimates include, rights-of-way, governmental permitting, design, materials, construction, construction management, and internal utility loads.
9. Project schedules are considered reasonably accurate but can be affected by permitting delays, equipment deliveries, weather, availability of workforce, and availability of outage clearance for construction.
10. The proposed schedule for final design and construction is estimated to take 36 months from an authorization to begin work.

Additional details are included in Appendix C.

10. CONCLUSION

Steady-State Performance

The following upgrades are required to accommodate the interconnection for SGI-PNM-2010-02:

- Construction of a new three (3) terminal 115 kV ring bus switching station (expandable to a breaker and half scheme) just south of the Tri-State owned Estancia distribution substation on the Willard–Britton 115 kV line section.

POI Reactive Power Analysis

The reactive power analysis indicates reactive power capability of the Project is adequate to achieve a +/- 0.95 net power factor range at the POI.

It should be noted that the simplified equivalent collector system provided by the Interconnection Customers for the solar facilities do not allow for a detailed evaluation of reactive requirements from each individual solar panel to the POI. This analysis only provides an indication of reactive power requirements and it remains the Interconnection Customer's responsibility to design their generation facilities and additional supplemental reactive support to meet the requirements at the POI.

11. APPENDIX A: Transmission Service Sensitivity Powerflow Maps

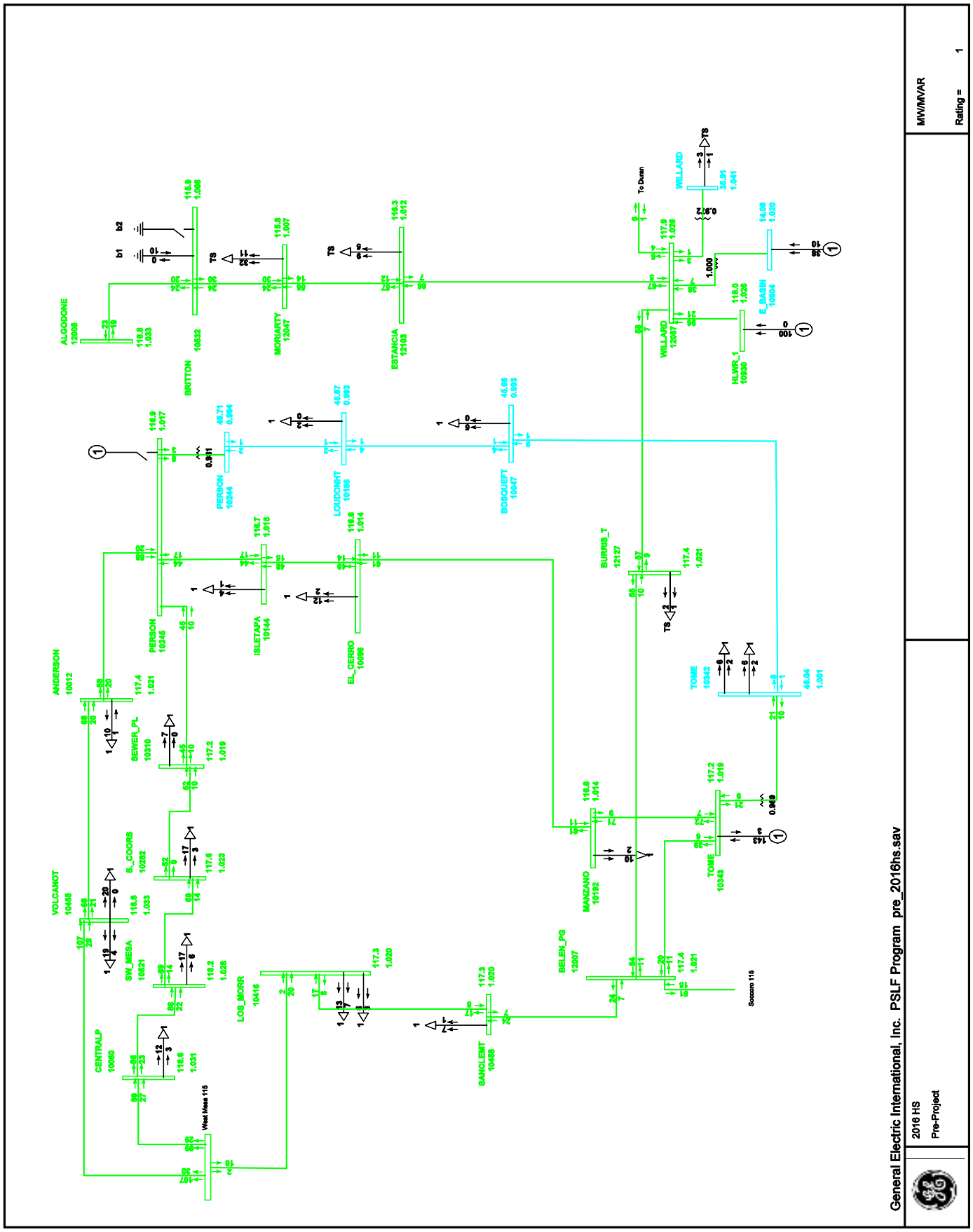


Figure A-1--Pre-Project 2016 HS

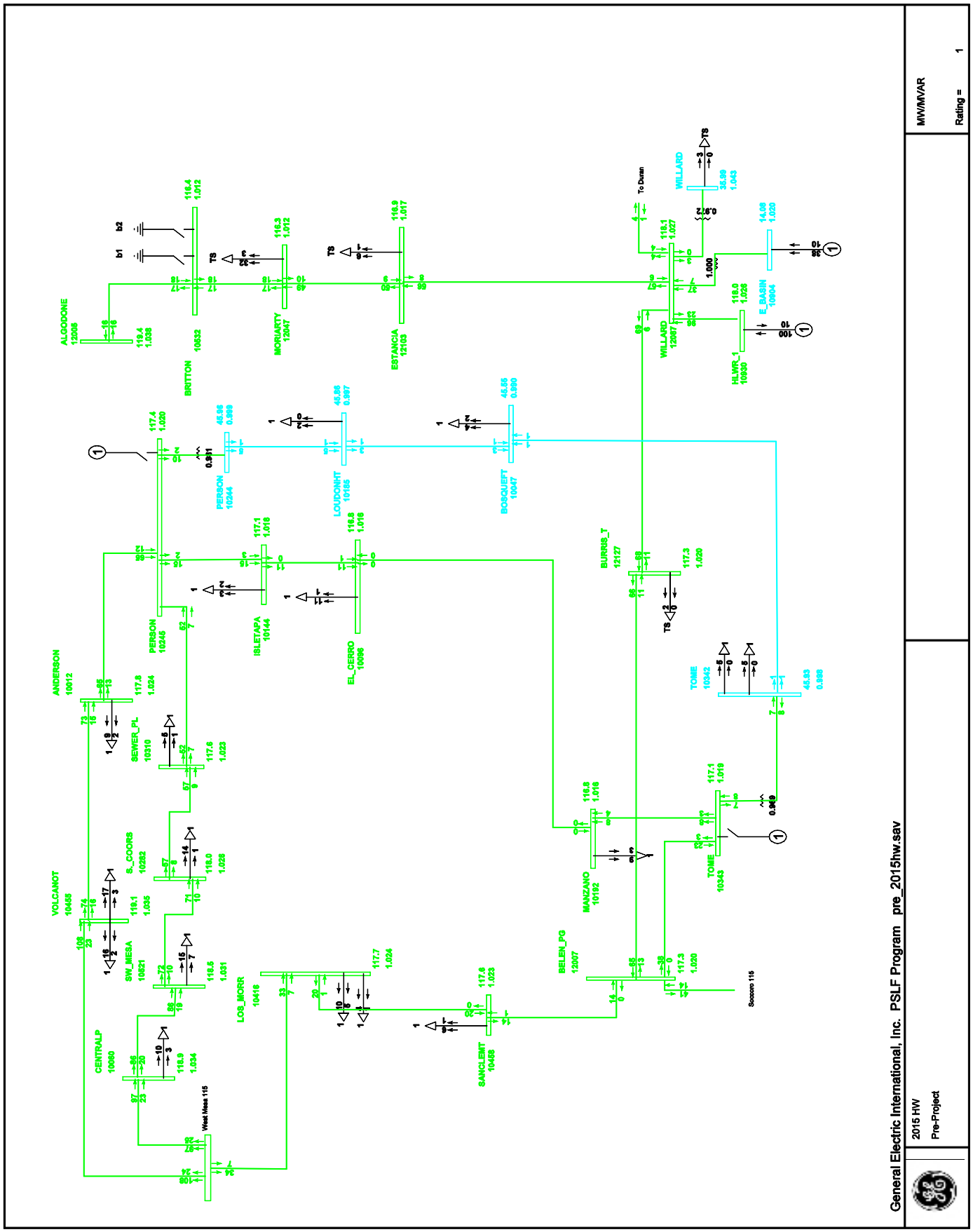


Figure A-2--Pre-Project 2015 HW

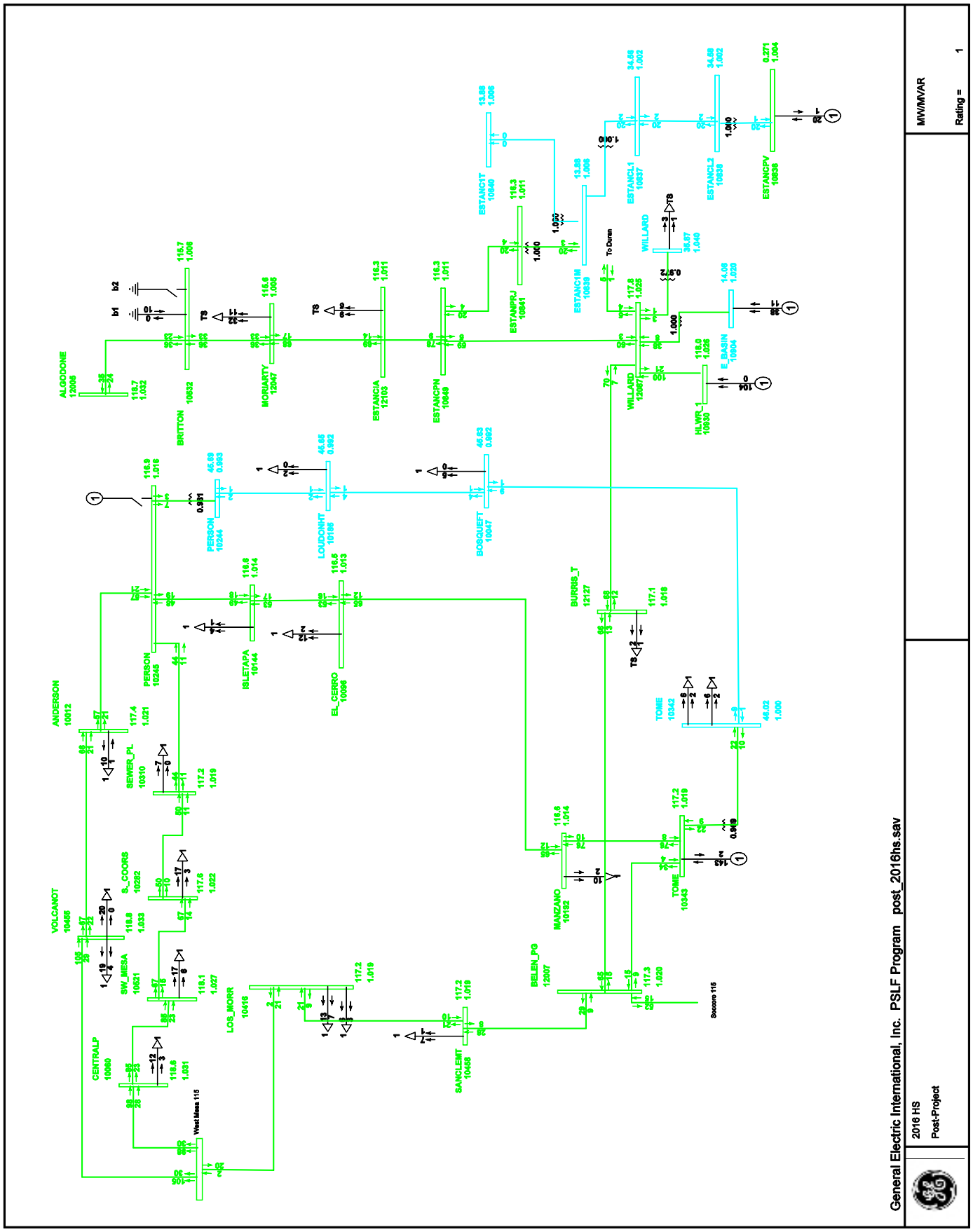


Figure A-3--Post-Project 2016 HS

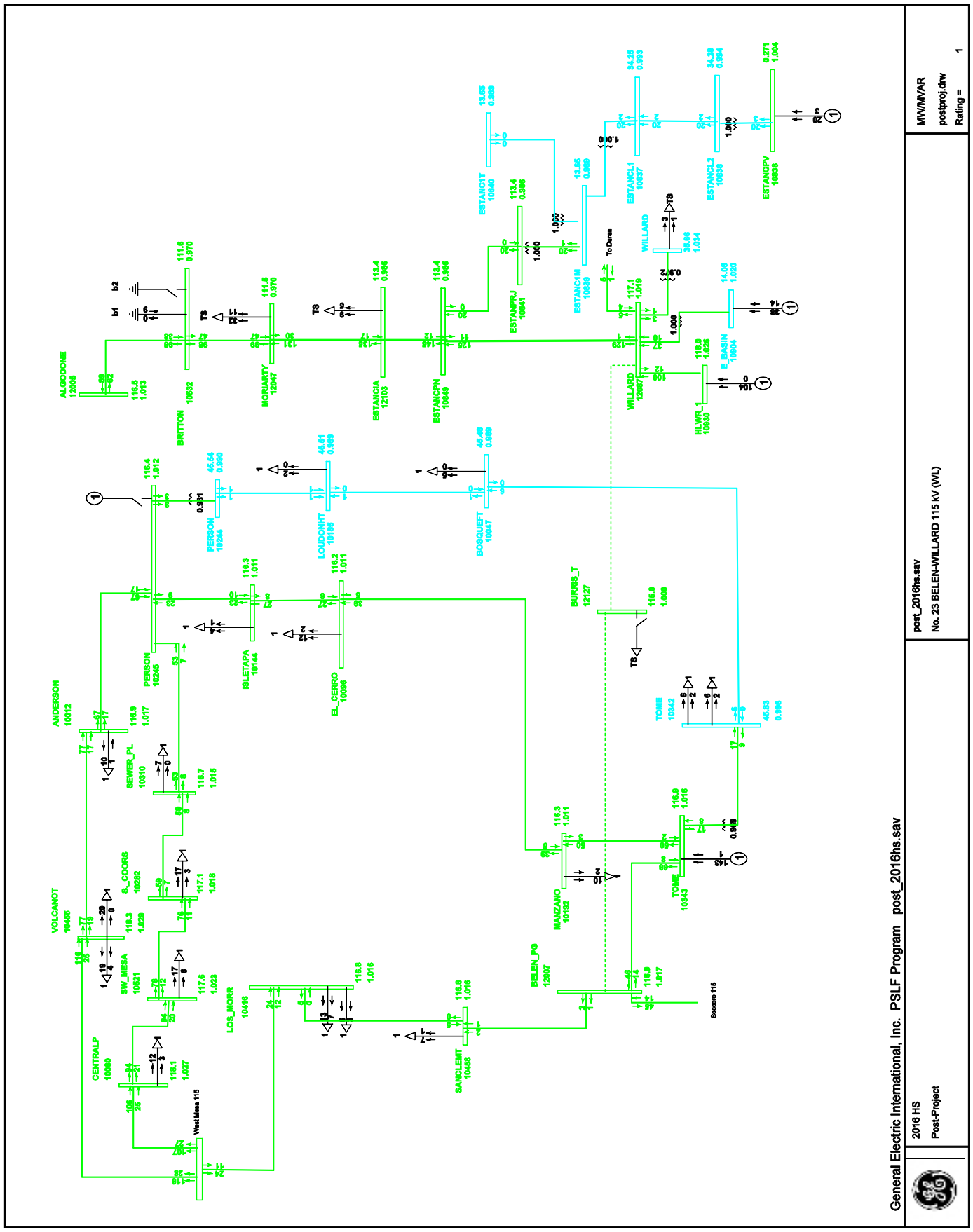


Figure A-4--Post-Project 2016 HS; Belen-Willard 115 kV N-1 line outage

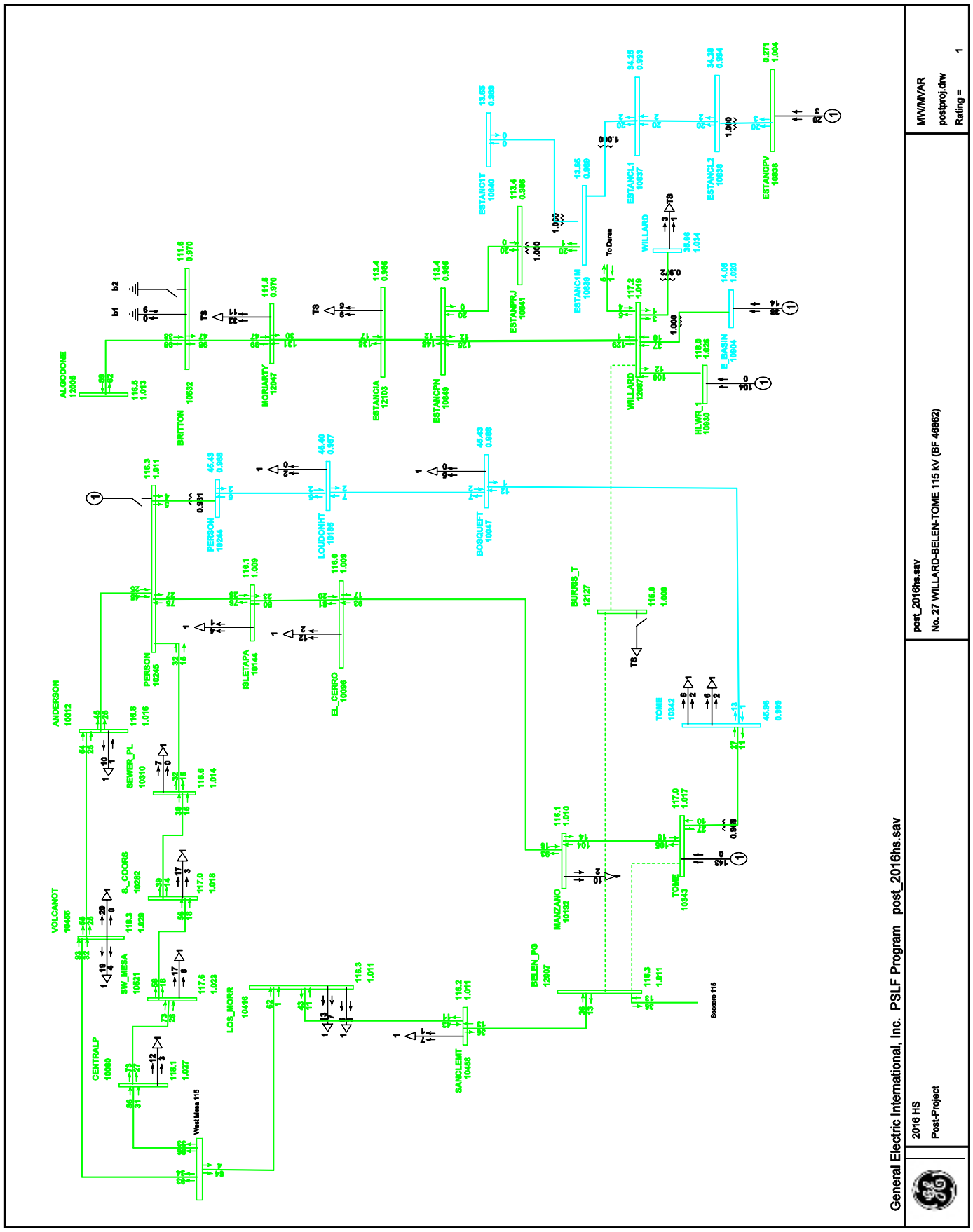


Figure A-5--Post-Project 2016 HS; Willard-Belen-Tome 115 kV N-2 line outage

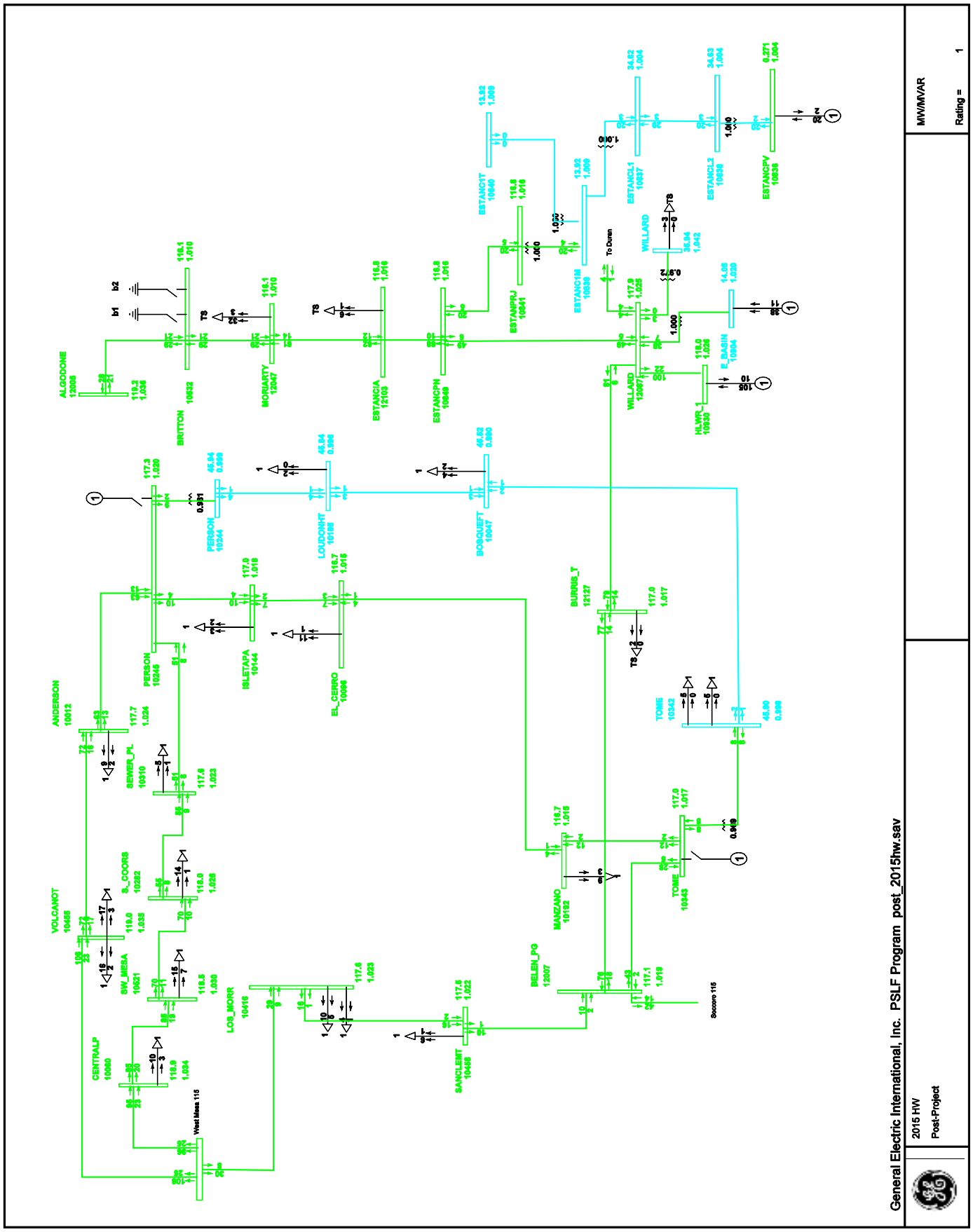


Figure A-6--Post-Project 2015 HW

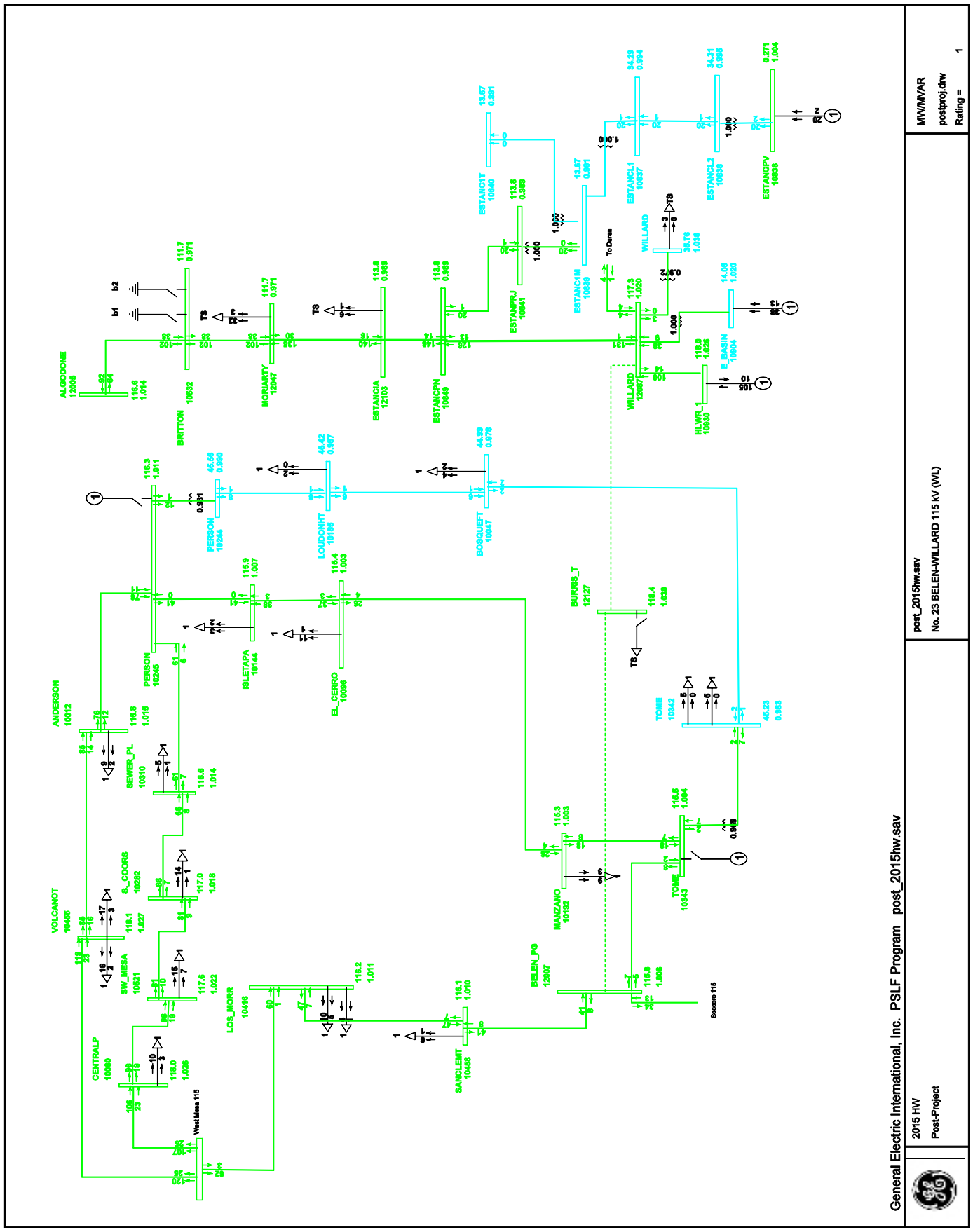


Figure A-7--Post-Project 2016 HS; Willard-Belen-Tome 115 kV N-2 line outage

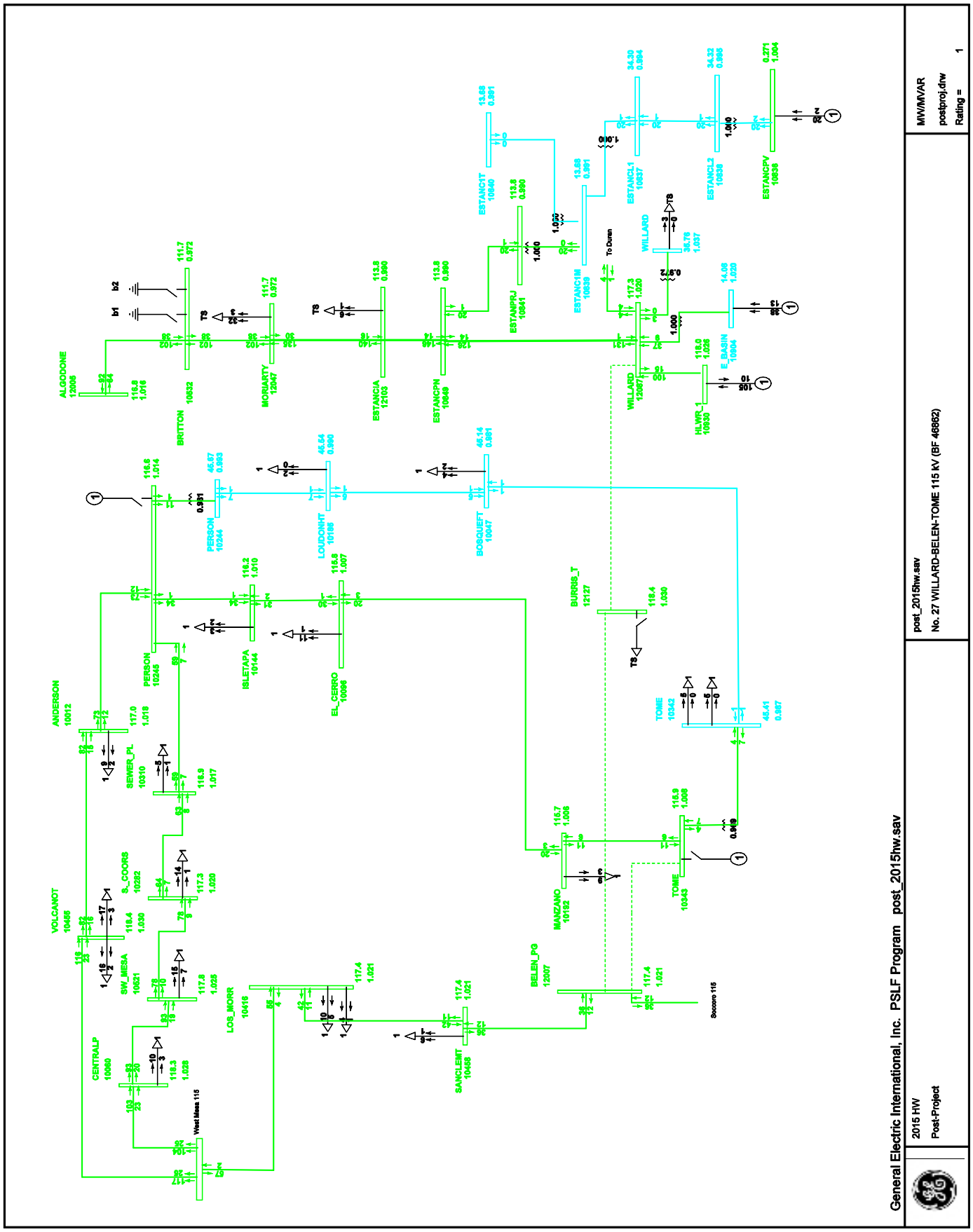
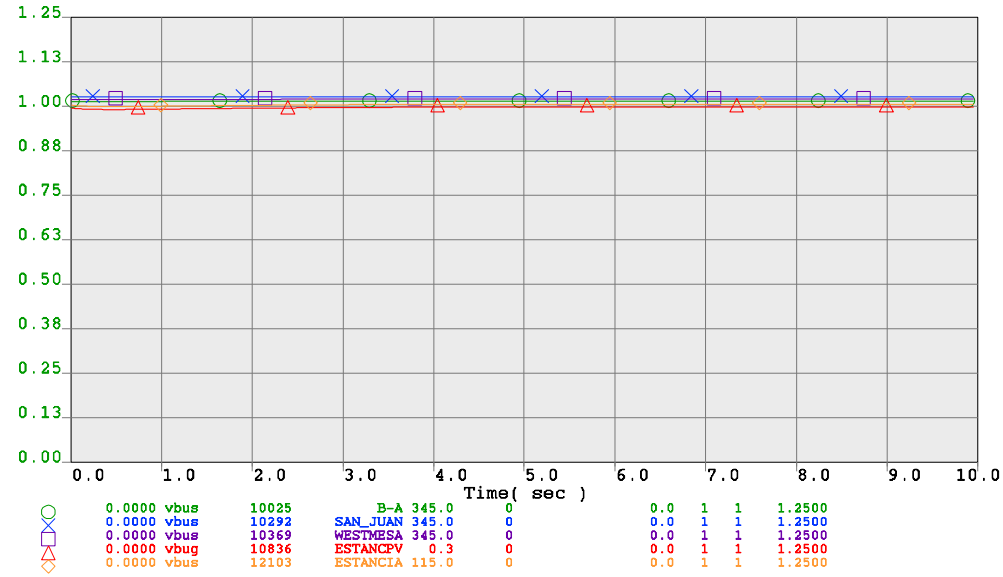
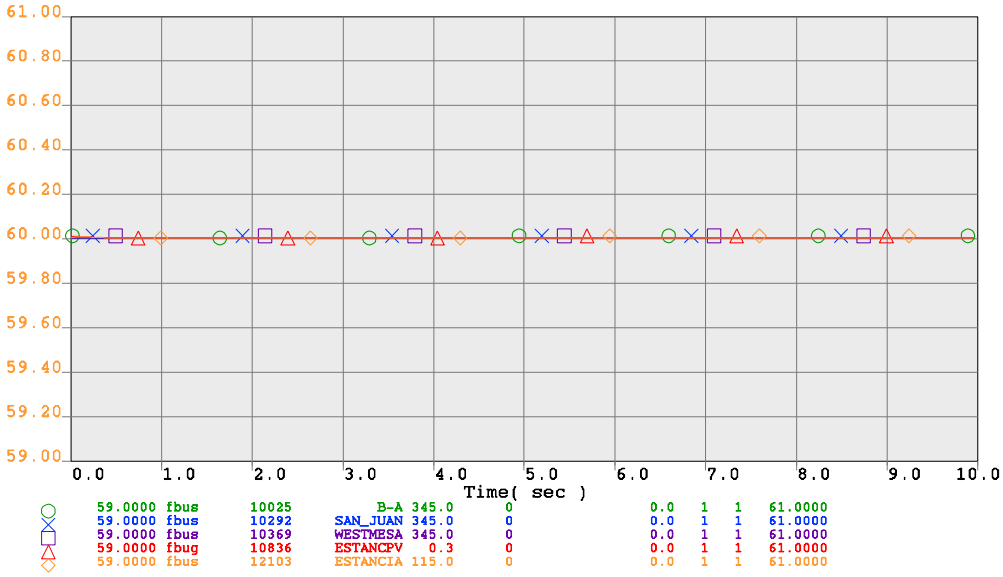


Figure A-8--Post-Project 2015 HW; Willard-Belen-Tome 115 kV N-2 line outage

12. APPENDIX B: Transmission Service Sensitivity Stability Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
No Disturbance

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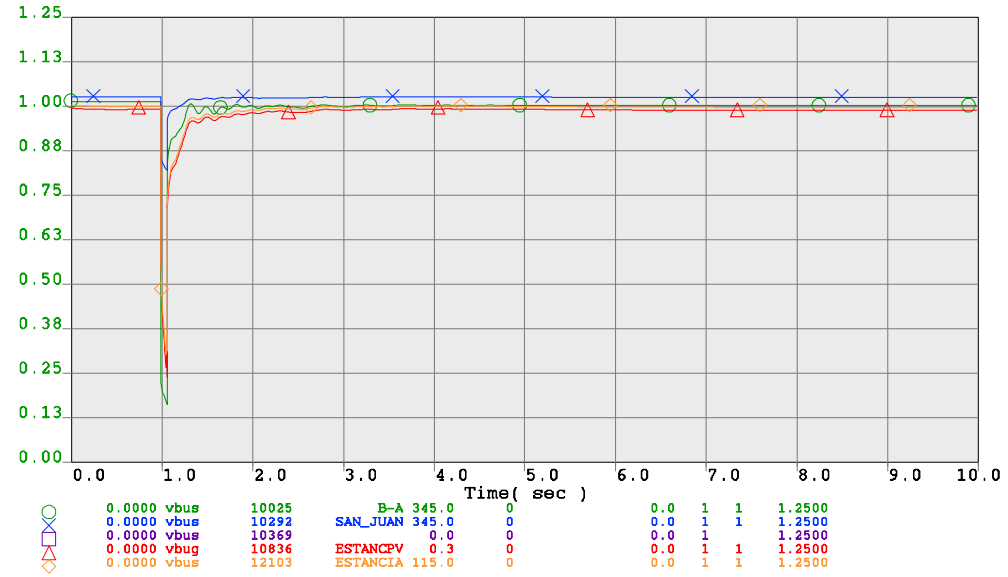
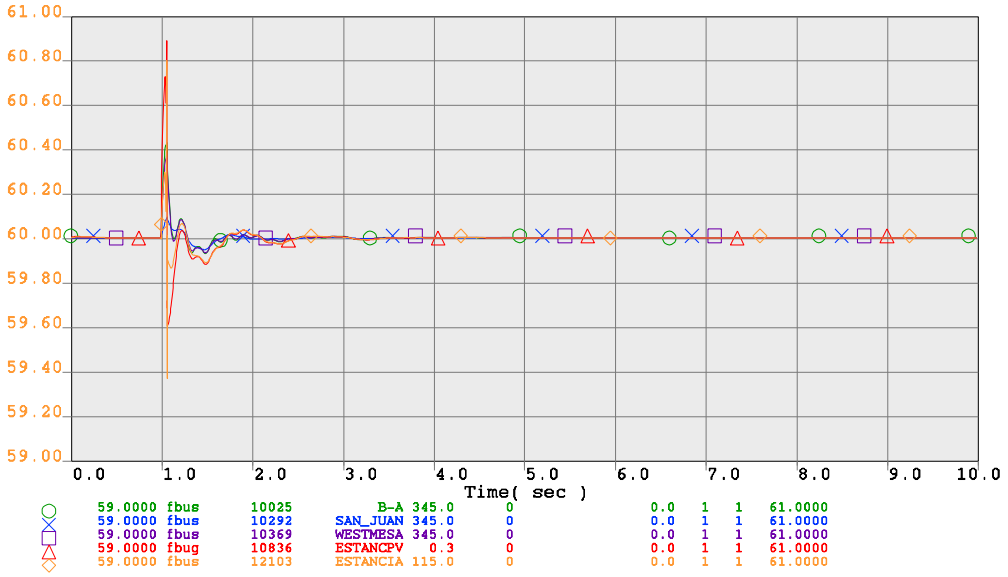
nodisturbl20posths.chf

Tue Sep 25 10:20:34 2012

Figure B-1--2016 HS----No Disturbance--Voltage and Frequency Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at West Mesa 345 kV bus;
Trip West Mesa-Arroyo in 4 cycles.

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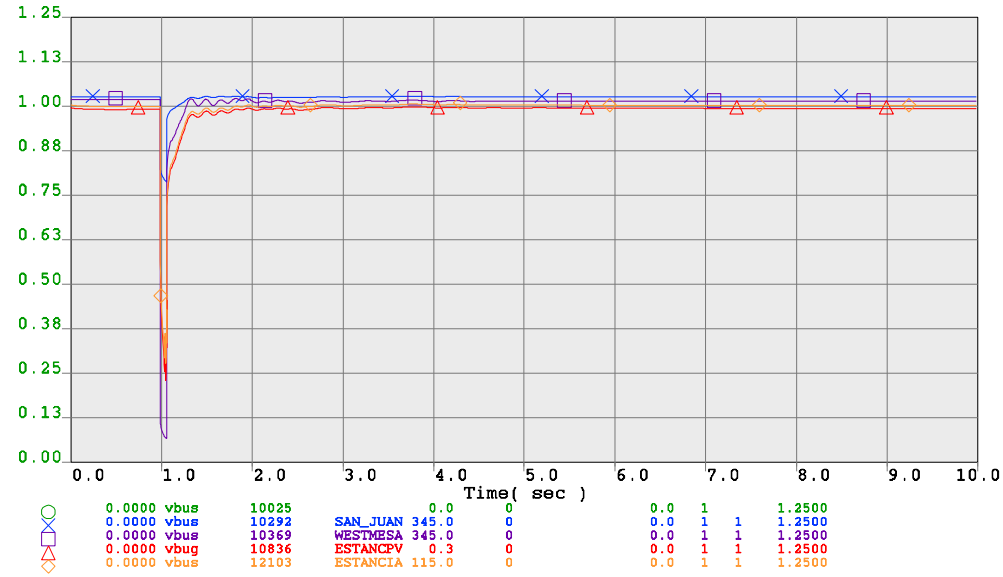
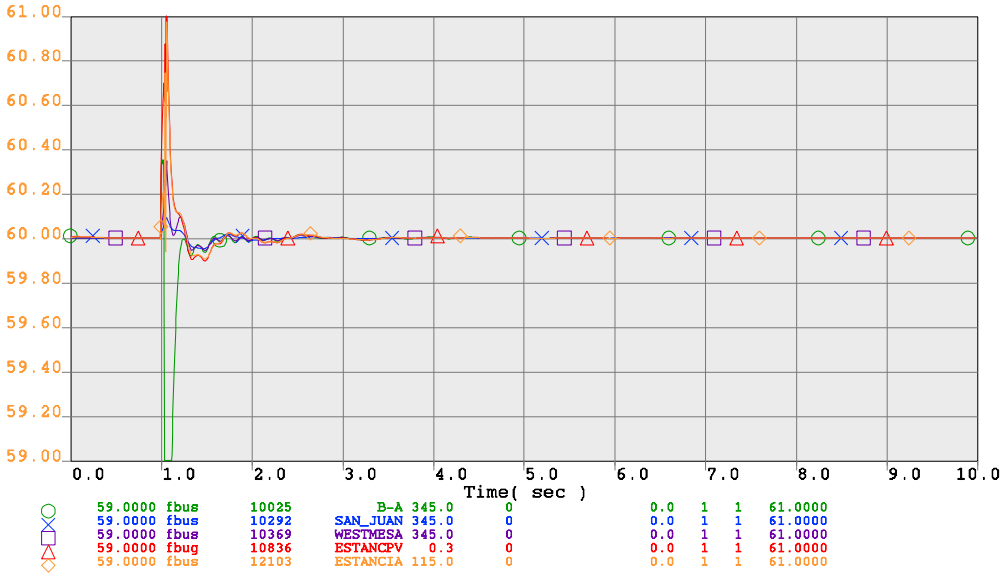
Figure B-2--2016 HS----3 Phase Fault at West Mesa 345 kV; Open West Mesa to Arroyo 345 kV line--Voltage and Frequency Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at Rio Puerco 345 kV bus;
Trip Rio Puerco-West Mesa 345 kV Line in 4 cycles.

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120_hs_sav_post_RPWM.chf

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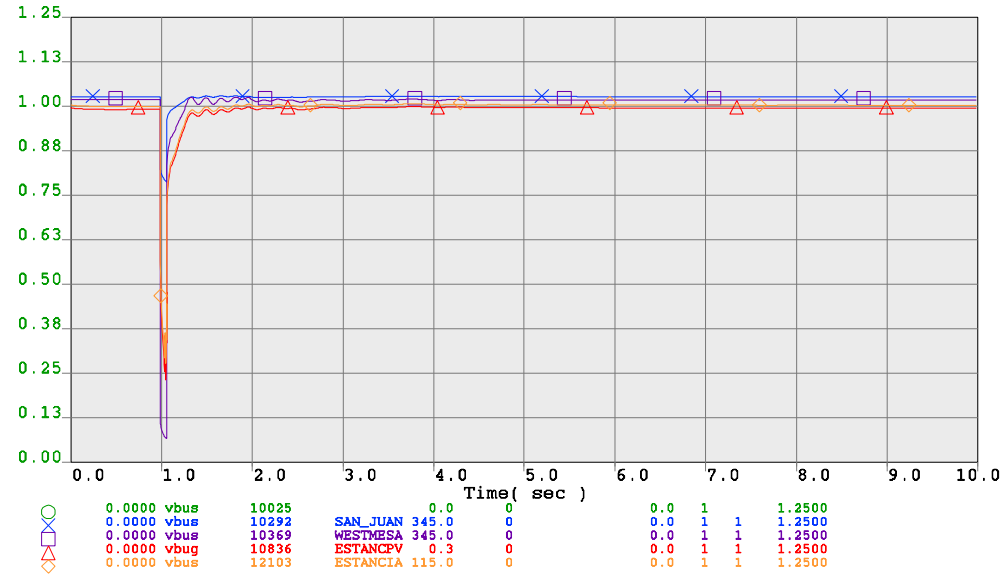
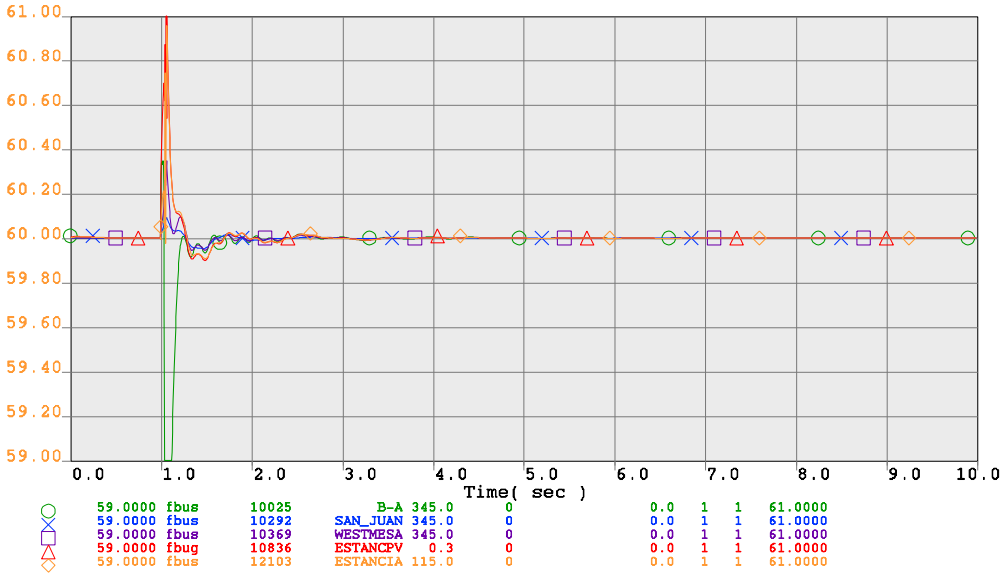
Figure B-3--2016 HS----3 Phase Fault at Rio Puerc 345 kV; Open Rio Puerco to West Mesa 345 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at BA 345 kV bus;
Trip Rio Puerco-BA 345 kV Line in 4 cycles.

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120_hs_sav_post_RPBA.chf

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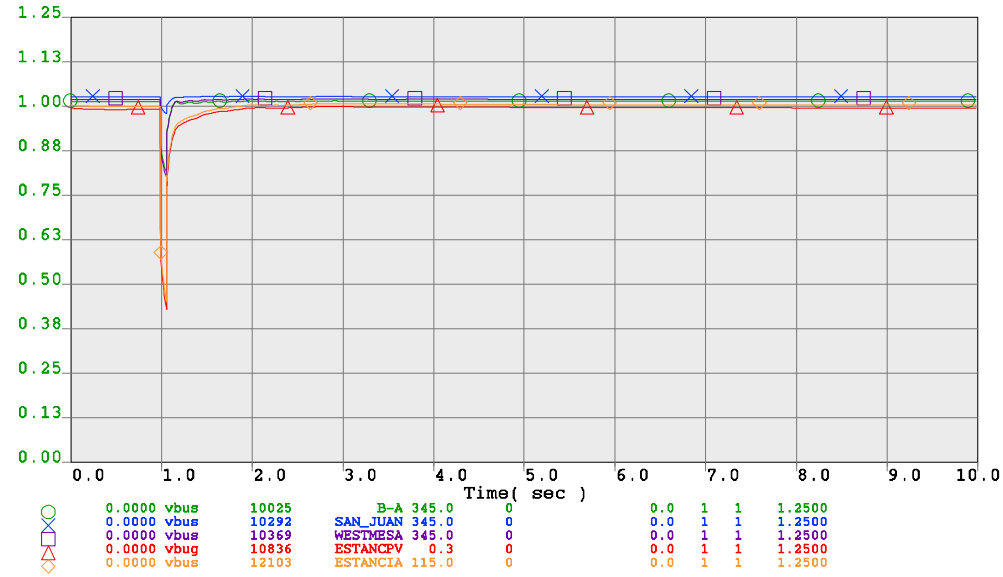
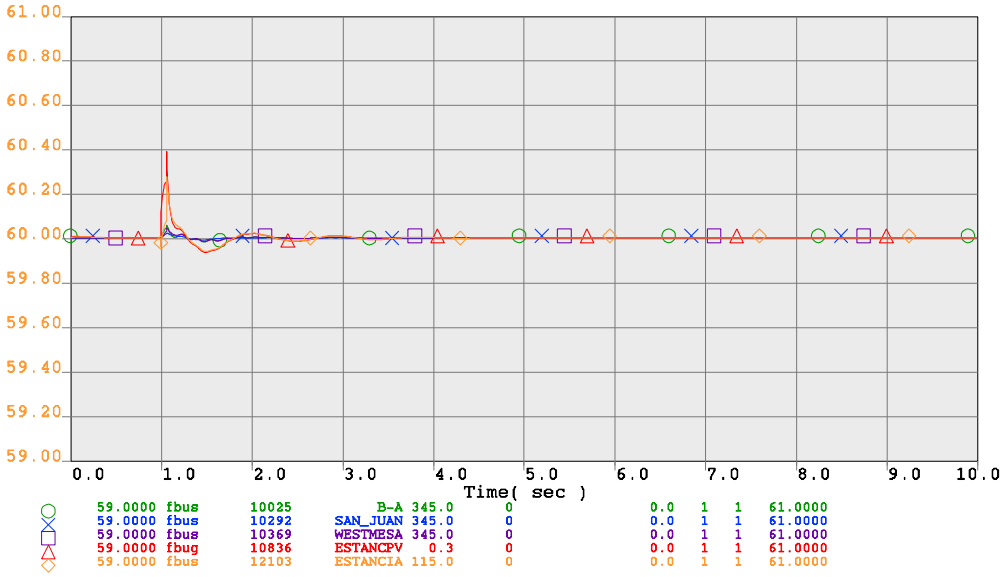
Figure B-4--2016 HS----3 Phase Fault at BA 345 kV; Open Rio Puerco to BA 345 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at TOME 115 kV bus;
Trip PERSON-TOME 115 kV Line in 4 cycles.

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120_hs_sav_post_PERTOME.chf

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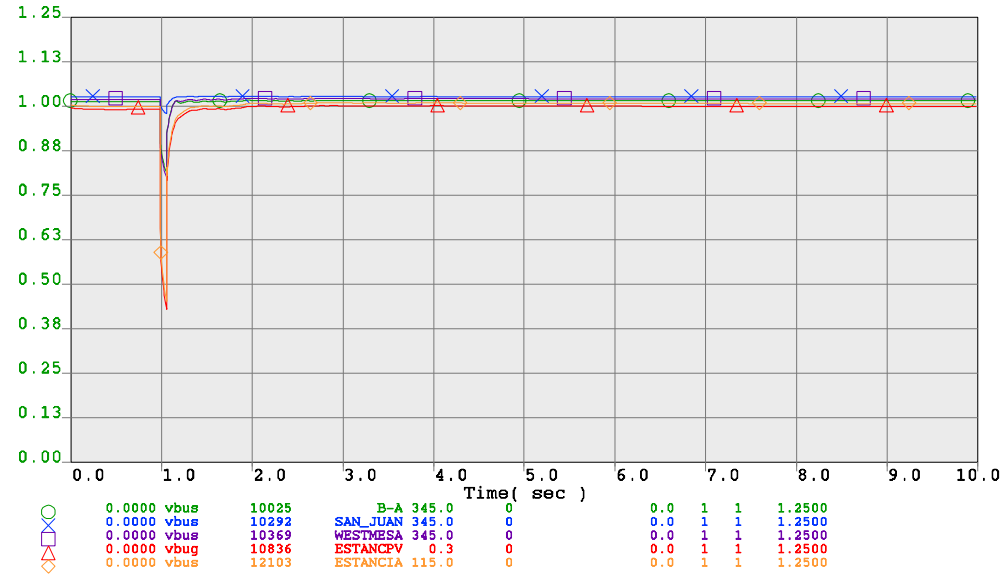
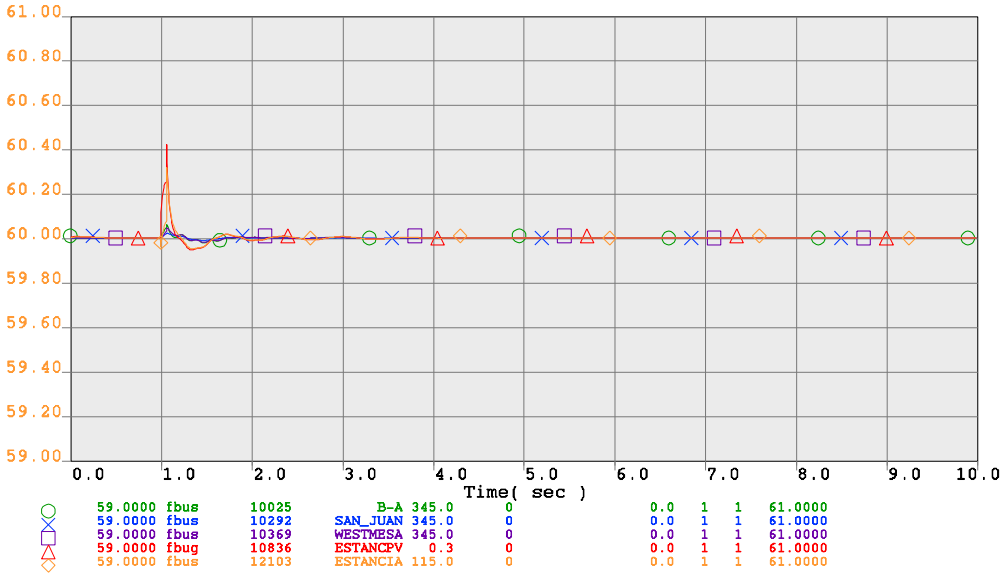
Figure B-5--2016 HS----3 Phase Fault at TOME 115 kV; Open PERSON to TOME 115 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME 115 kV Line in 4 cycles.

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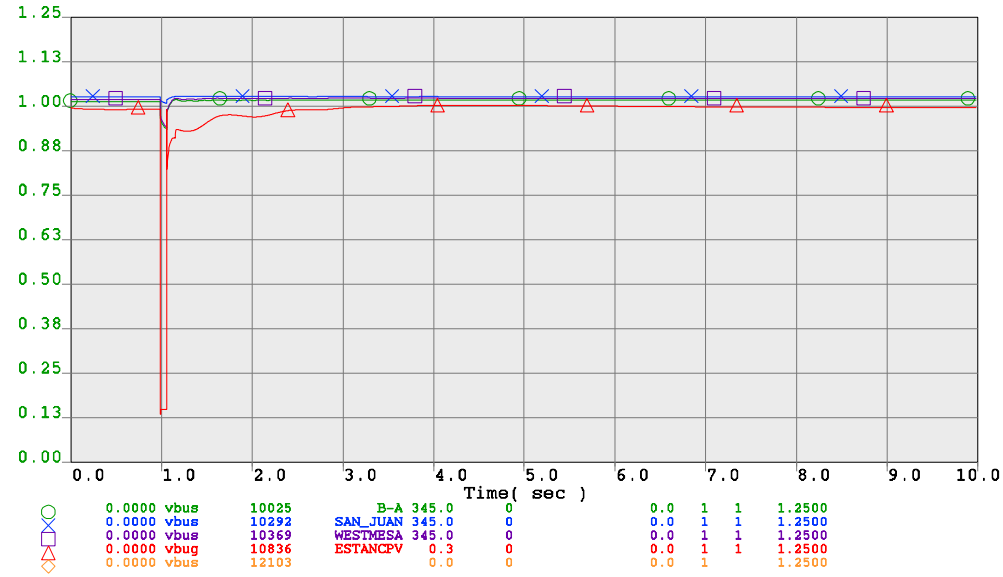
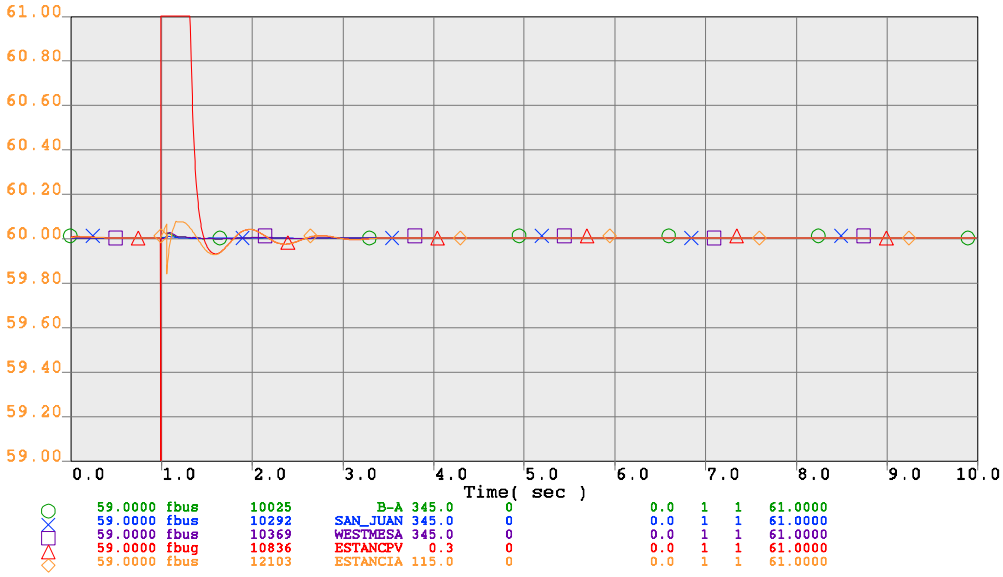
120_hs_sav_post_BELTOME.chf

Tue Sep 25 10:20:55 2012

Figure B-6--2016 HS----3 Phase Fault at TOME 115 kV; Open BELEN to TOME 115 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to TORRANCE_PNM 115 kV line in 4 cycles.

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120_hs_sav_post_TorrEst.chf

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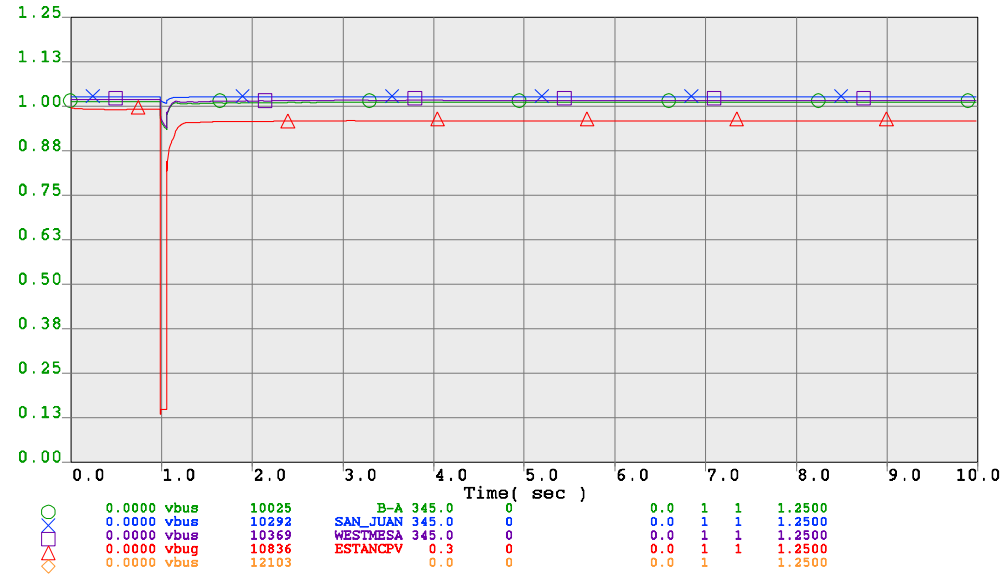
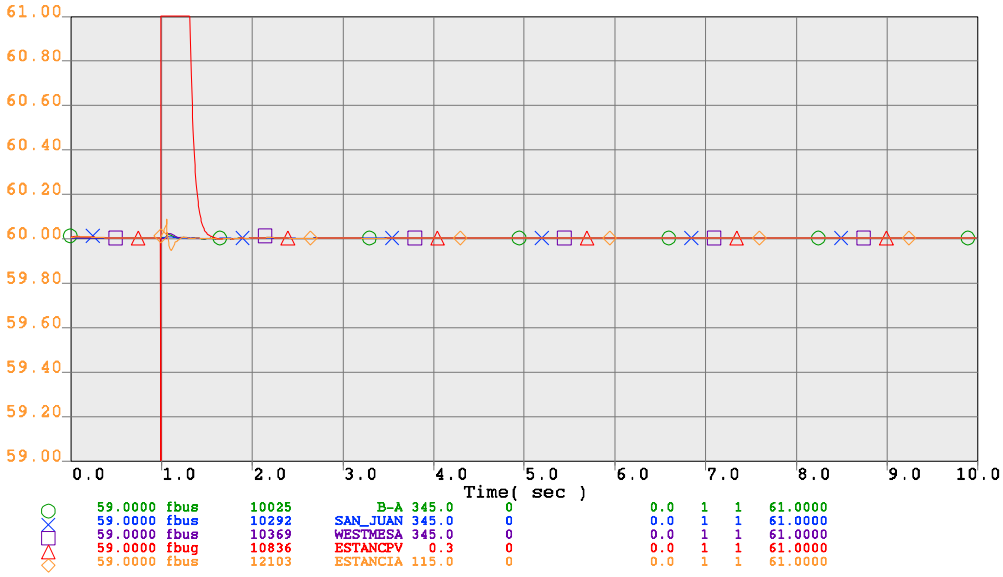
Figure B-7--2016 HS----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to Britton 115 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to WILLARD 115 kV line in 4 cycles.

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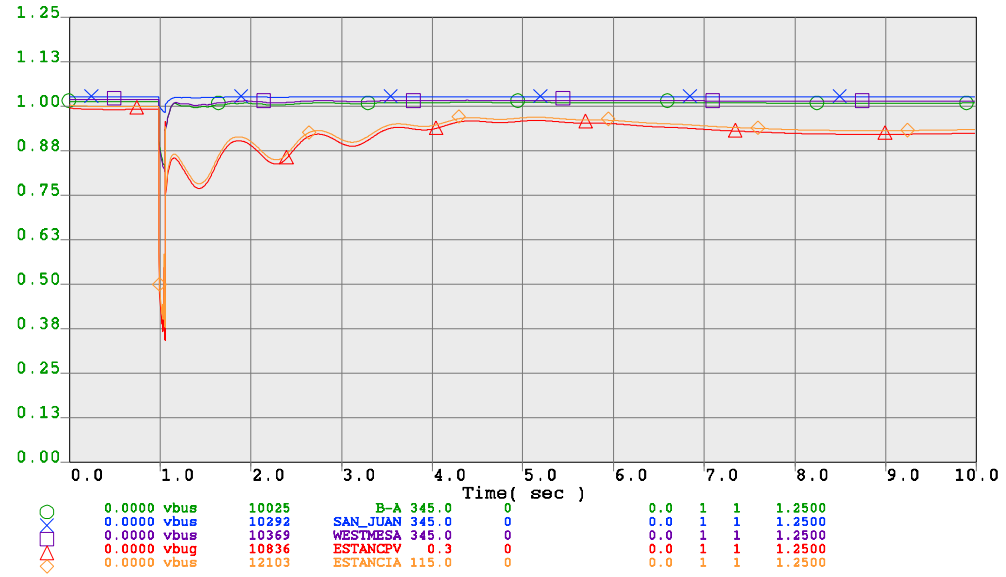
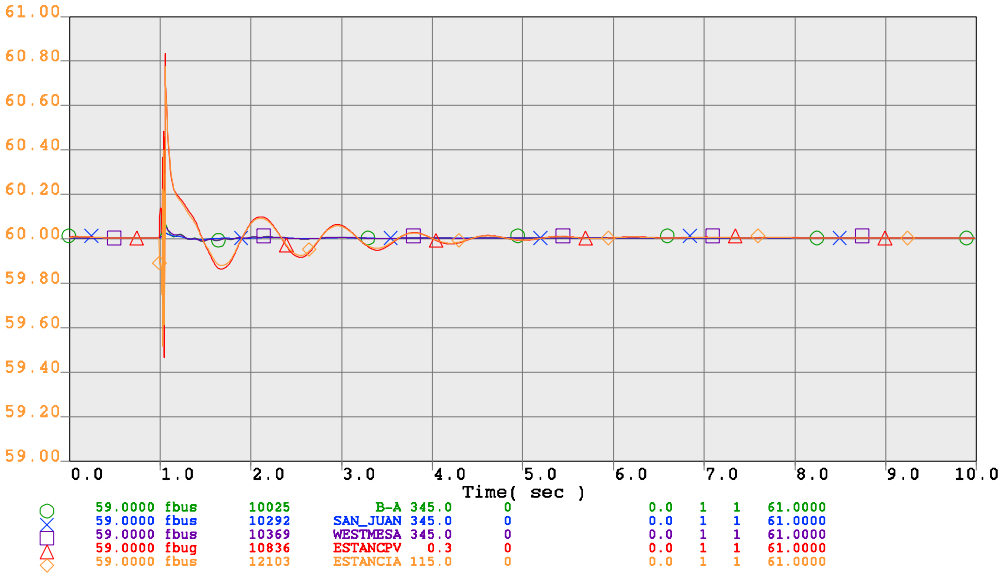
120_hs_sav_post_WillEst.chf

Tue Sep 25 16:37:40 2012

Figure B-8--2016 HS----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to WILLARD 115 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at BELEN 115 kV bus;
Trip BELEN_PG-TOME AND BELEN_PG 115 kV Lines in 4 cycles.

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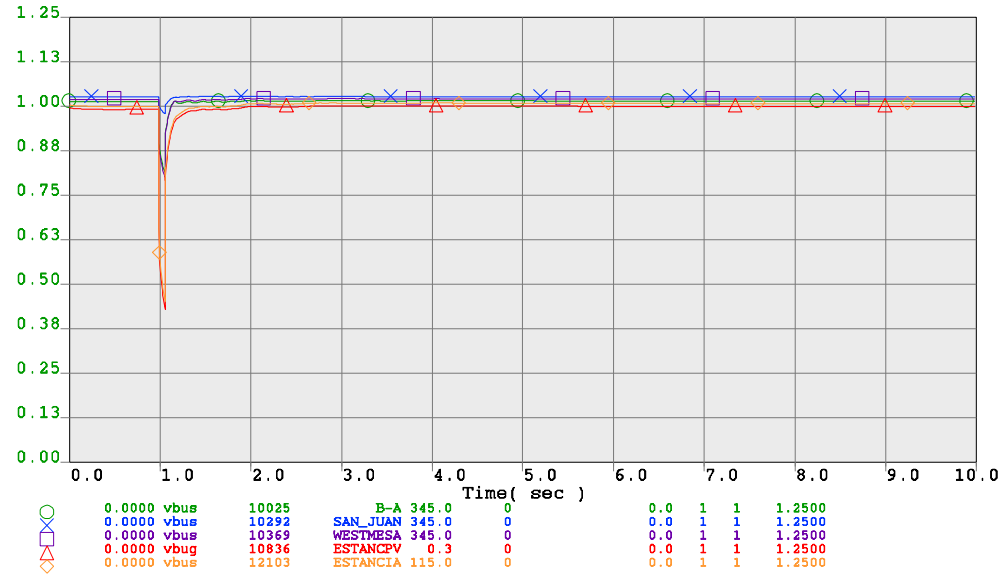
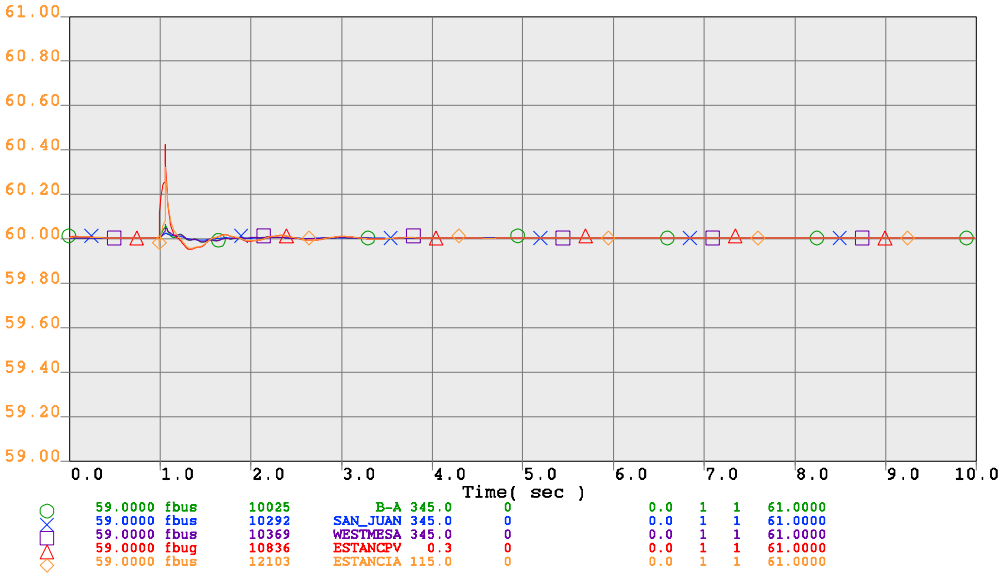
120_hs_sav_post_BELTOMEWILL.chf

Tue Sep 25 10:21:08 2012

Figure B-9--2016 HS----3 Phase Fault at BELEN 115 kV; Open BELEN to TOME AND BELEN to WILLARD 115 kV line--Voltage Plots





TYP 2016 HS WECC 2016HS2 APPROVED BASE CASE
SEPTEMBER 20, 2010
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME Line TOME 115/46 kV transformer in 4 cycles.

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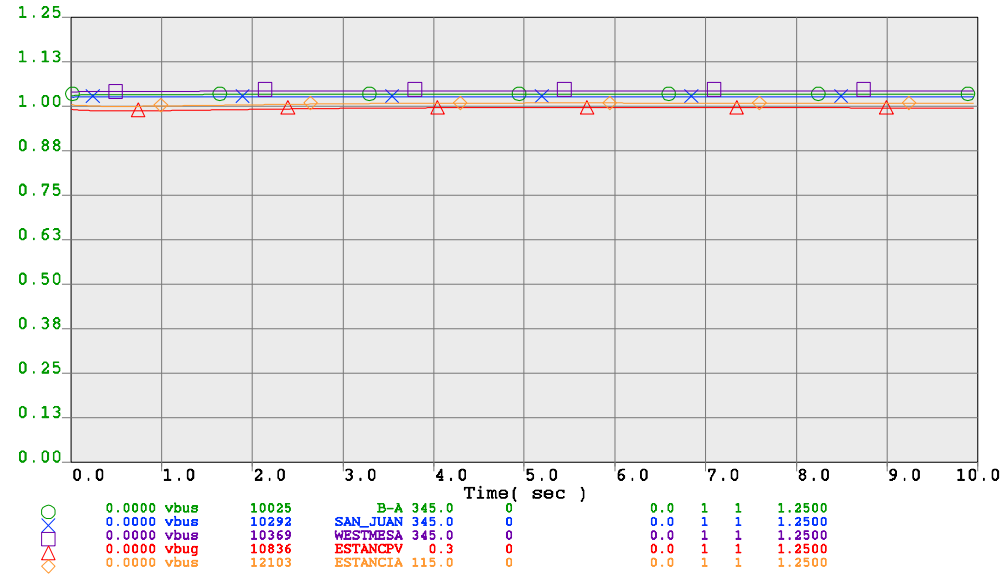
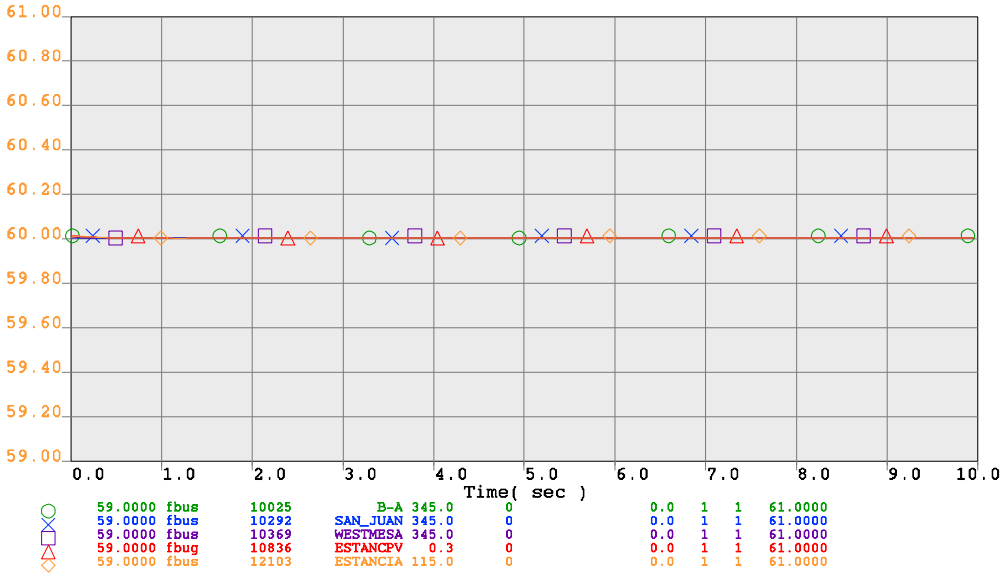
120_hs_sav_post_BELTOMETOMEXFMR.chf

Tue Sep 25 10:21:15 2012

Figure B-10--2016 HS----3 Phase Fault at TOME 115 kV; Open BELEN to TOME AND TOME 115/46 kV transformer--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
No Disturbance

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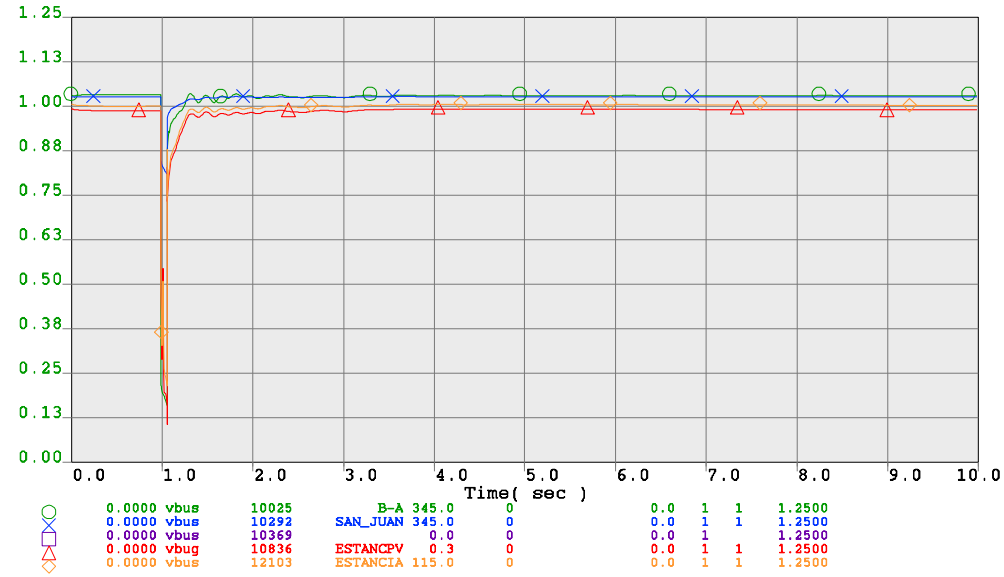
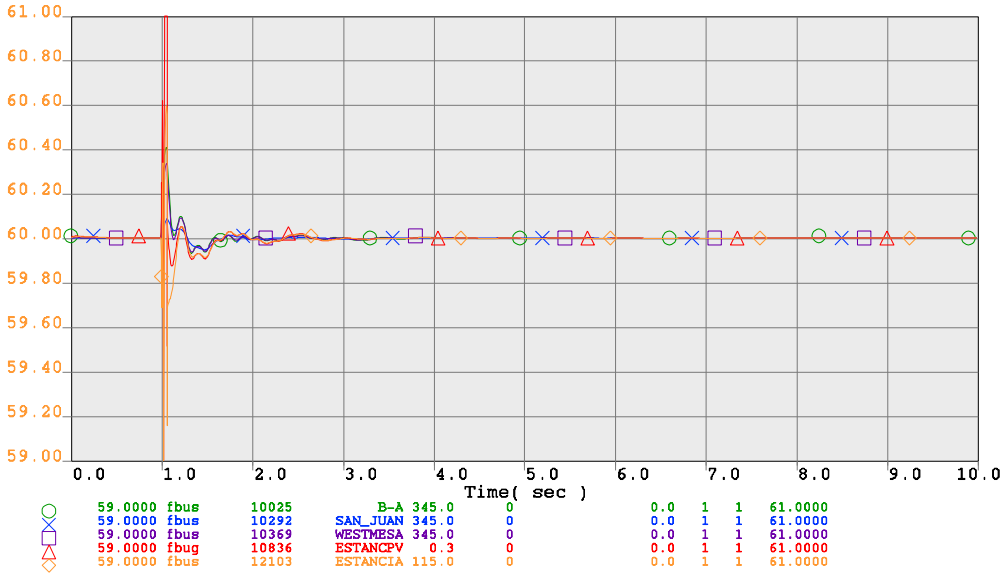
nodisturbl20posthw.chf

Tue Sep 25 10:28:58 2012

Figure B-11--2015 HW----No Disturbance--Voltage and Frequency Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at West Mesa 345 kV bus;
Trip West Mesa-Arroyo in 4 cycles.

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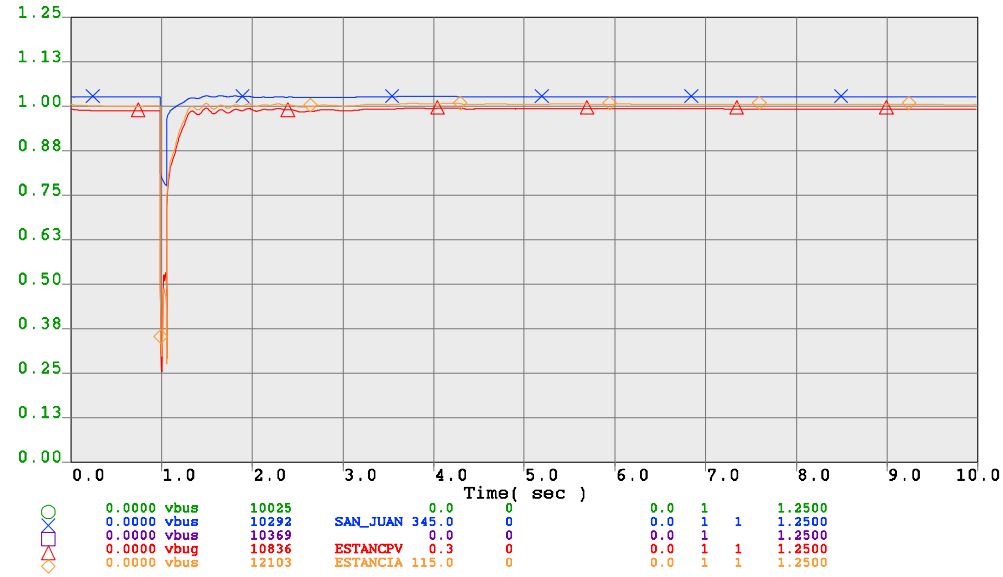
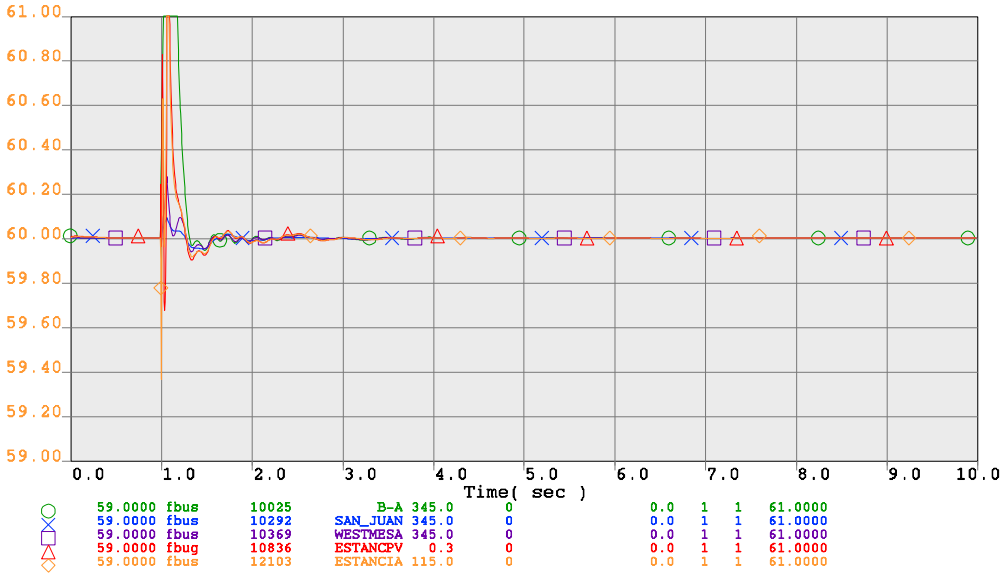
Figure B-12--2015 HW----3 Phase Fault at West Mesa 345 kV; Open West Mesa to Arroyo 345 kV line--Voltage and Frequency Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at Rio Puerco 345 kV bus;
Trip Rio Puerco-West Mesa 345 kV Line in 4 cycles.

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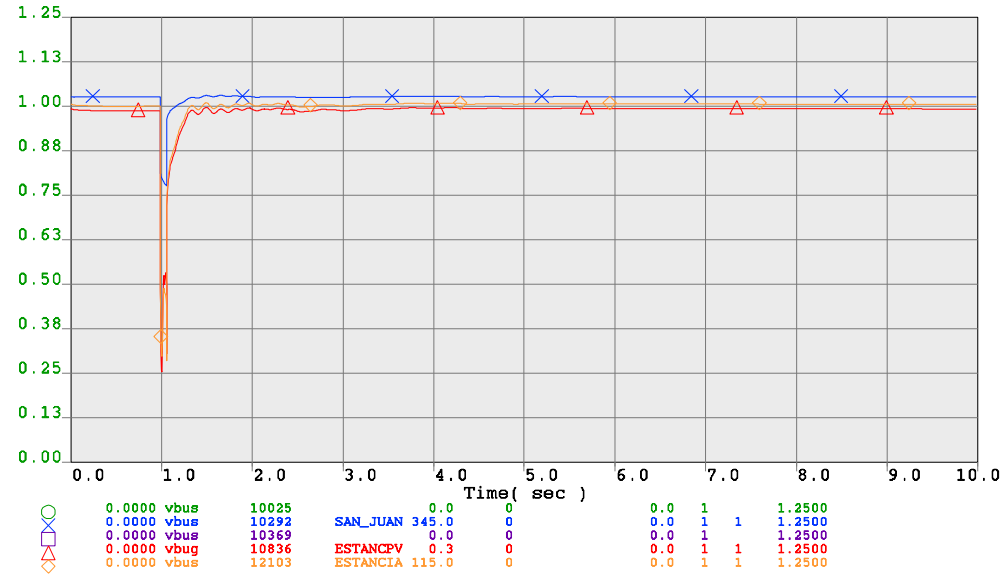
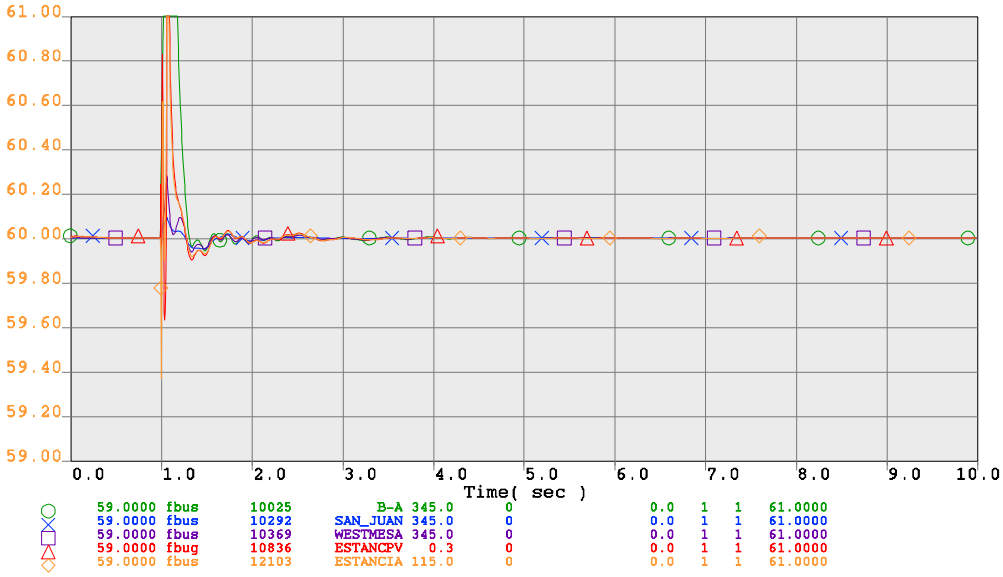
120_hw_sav_post_RPWM.chf

Tue Sep 25 10:29:04 2012

Figure B-13--2015 HW----3 Phase Fault at Rio Puerc 345 kV; Open Rio Puerco to West Mesa 345 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at BA 345 kV bus;
Trip Rio Puerco-BA 345 kV Line in 4 cycles.

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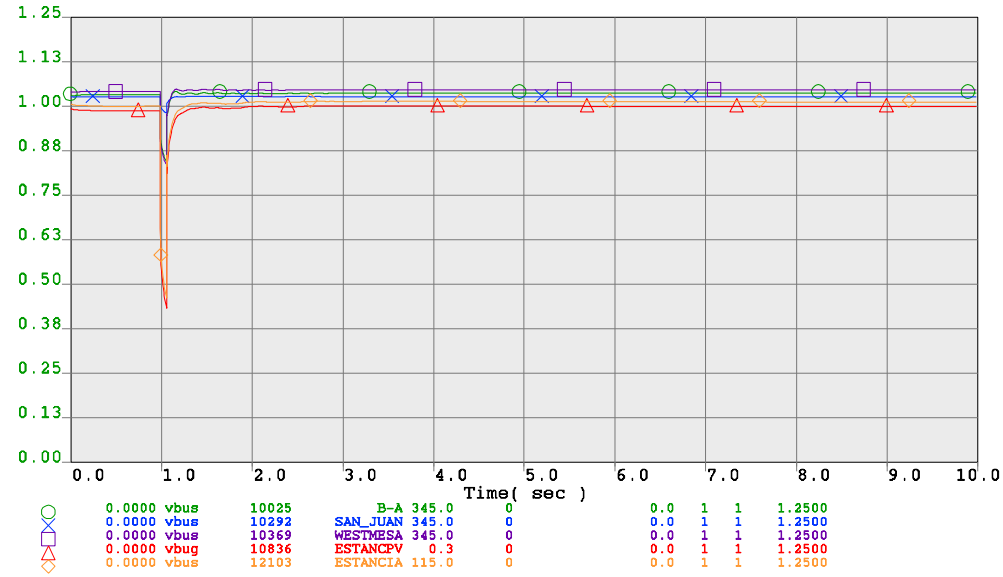
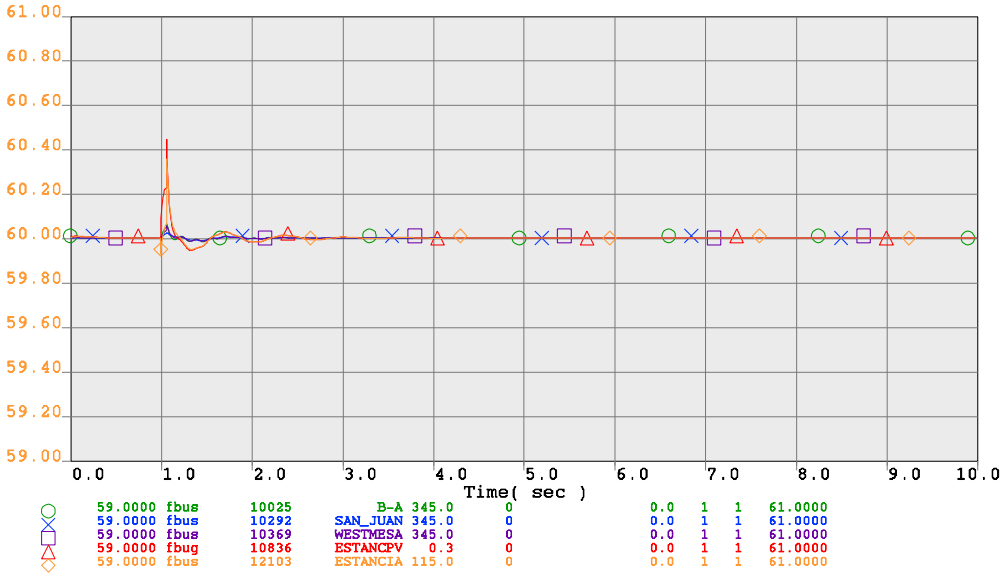
120_hw_sav_post_RPBA.chf

Tue Sep 25 10:29:10 2012

Figure B-14--2015 HW----3 Phase Fault at BA 345 kV; Open Rio Puerco to BA 345 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at TOME 115 kV bus;
Trip PERSON-TOME 115 kV Line in 4 cycles.

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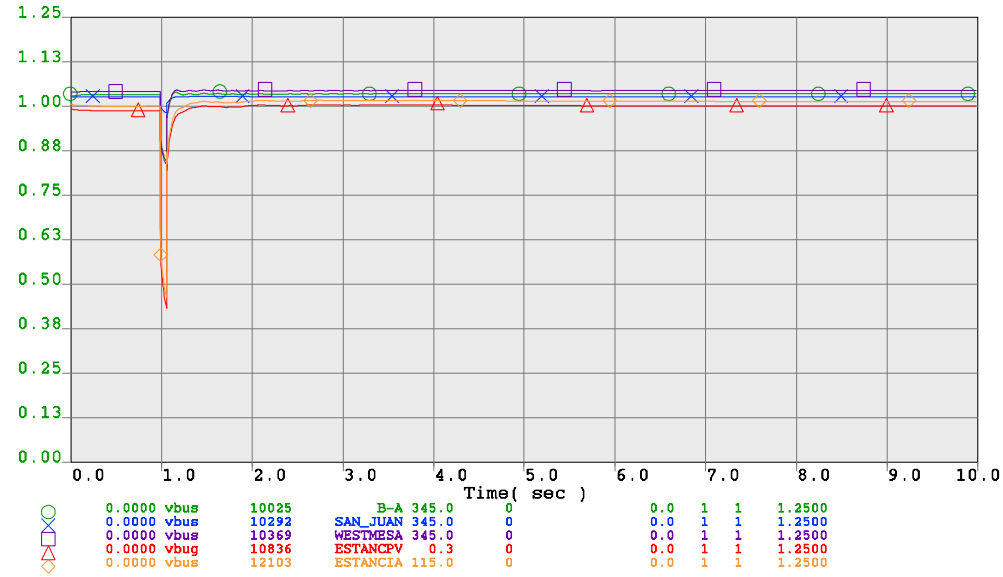
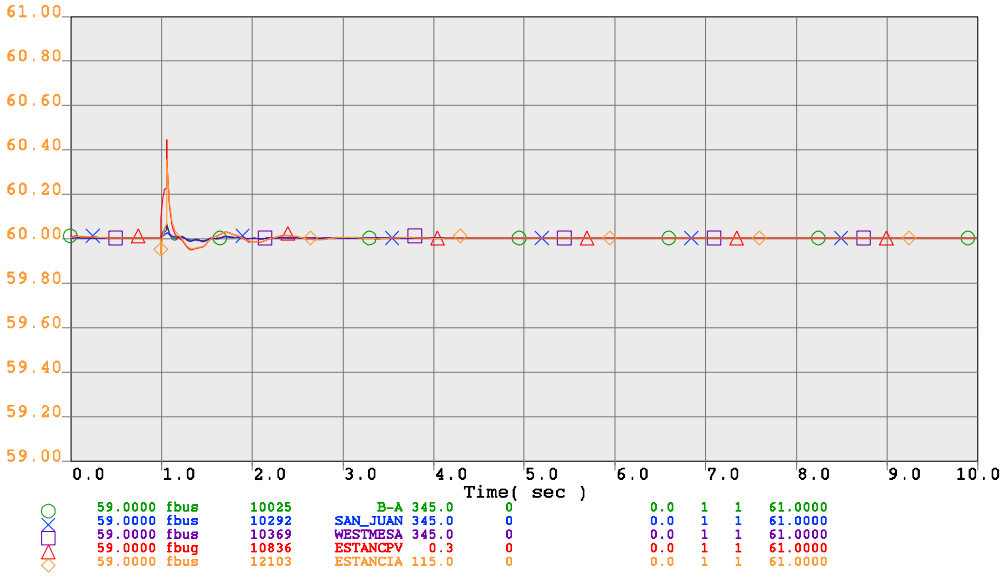
120_hw_sav_post_PERTOME.chf

Tue Sep 25 10:29:23 2012

Figure B-15--2015 HW----3 Phase Fault at TOME 115 kV; Open PERSON to TOME 115 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME 115 kV Line in 4 cycles.

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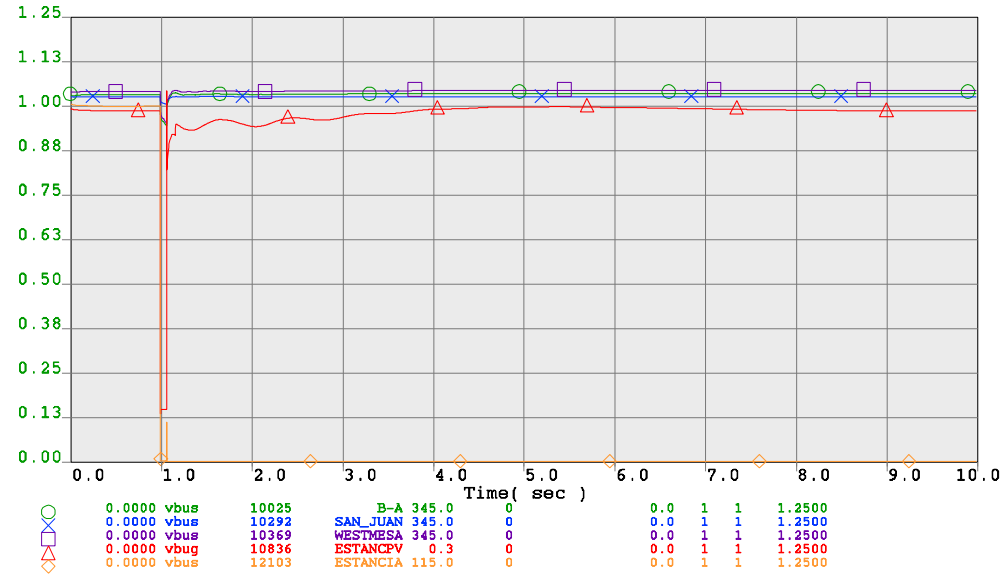
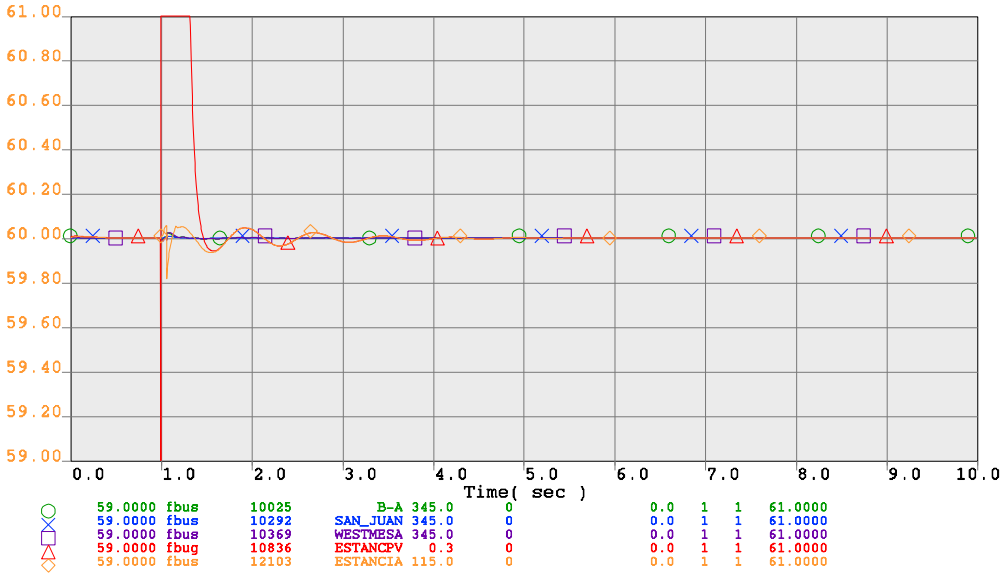
120_hw_sav_post_BELTOME.chf

Tue Sep 25 10:29:17 2012

Figure B-6--2015 HW----3 Phase Fault at TOME 115 kV; Open BELEN to TOME 115 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to TORRANCE_PNM 115 kV line in 4 cycles.

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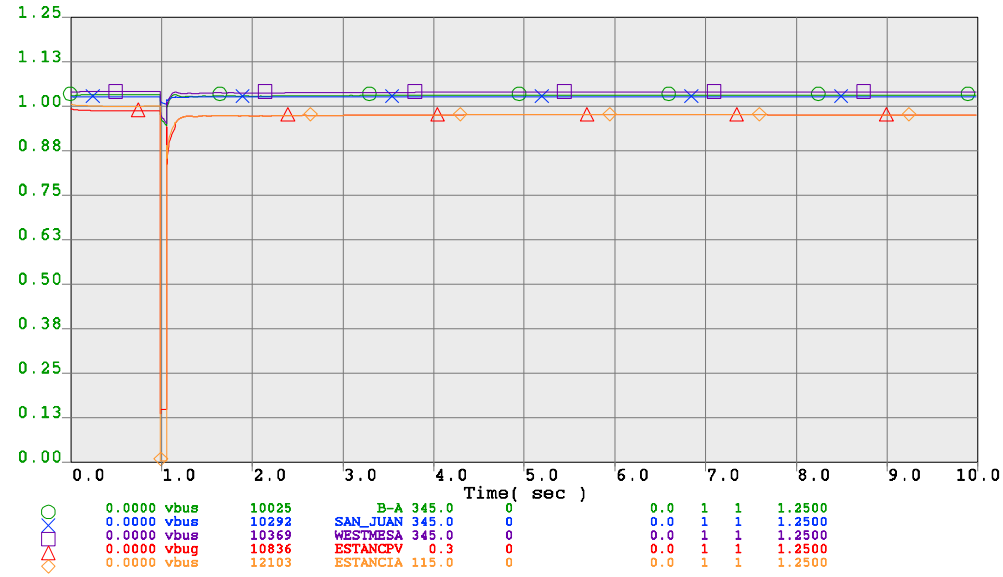
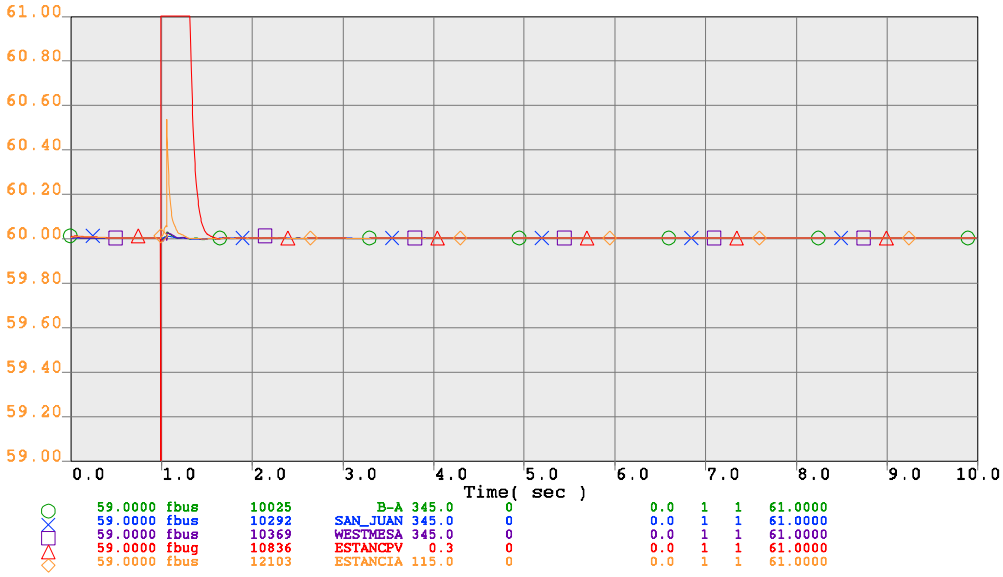
120_hw_sav_post_TorrEst.chf

Tue Sep 25 16:38:00 2012

Figure B-17--2015 HW----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to Britton 115 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at ESTANCPN 115 kV bus;
Trip ESTANCPN to WILLARD 115 kV line in 4 cycles.

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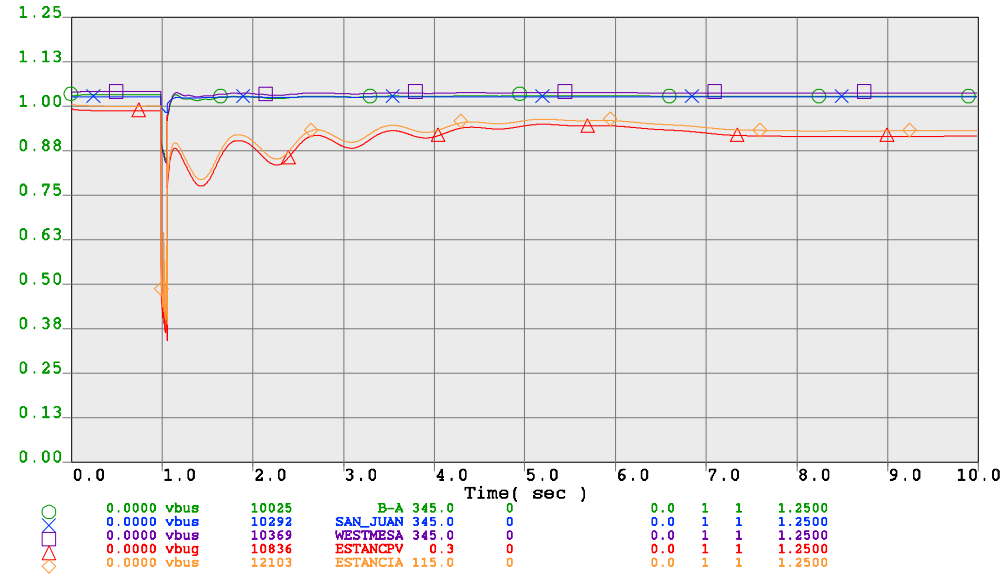
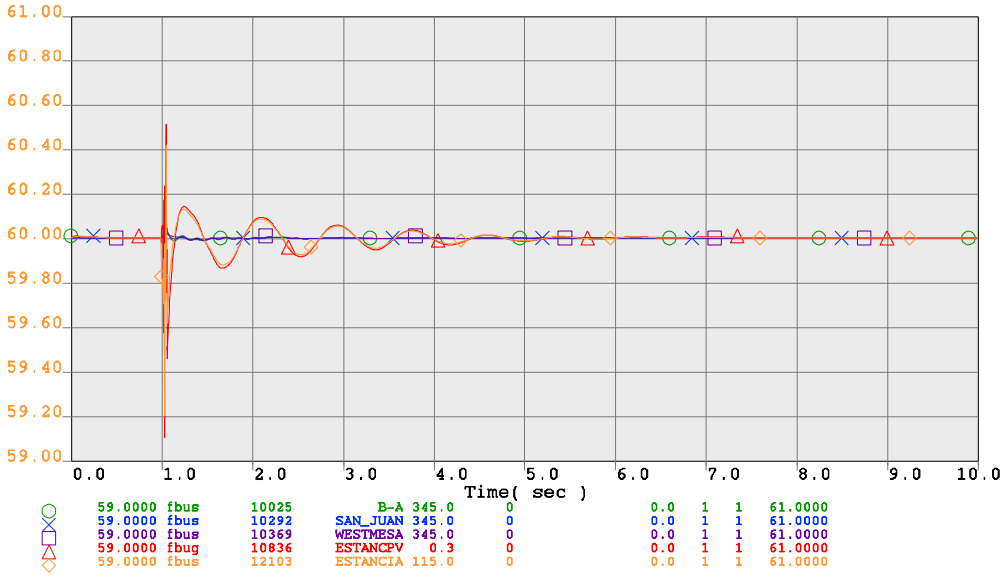
120_hw_sav_post_WillEst.chf

Tue Sep 25 16:37:53 2012

Figure B-18--2015 HW----3 Phase Fault at ESTANCPN 115 kV; Open ESTANCPN to WILLARD 115 kV line--Voltage Plots





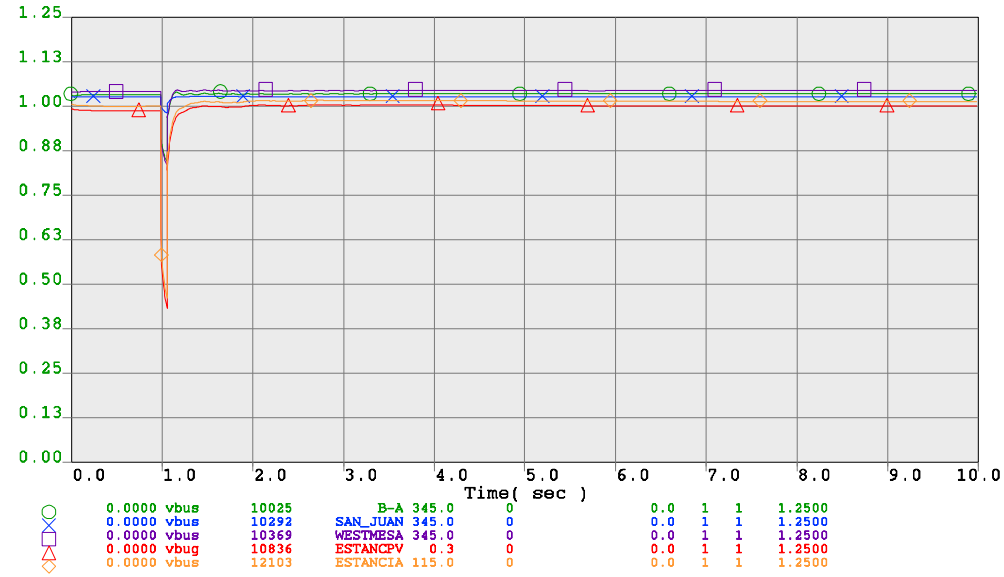
TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at BELEN 115 kV bus;
Trip BELEN_PG-TOME AND BELEN_PG 115 kV Lines in 4 cycles.

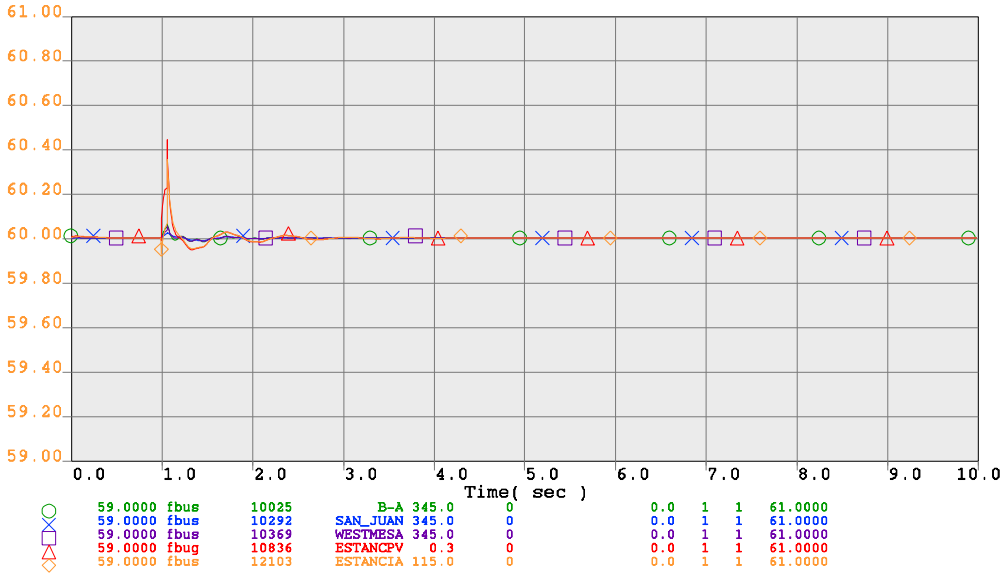
Page 1

120_hw_sav_post_BELTOMEWILL.chf

Tue Sep 25 10:29:30 2012

Figure B-19--2015 HW----3 Phase Fault at BELEN 115 kV; Open BELEN to TOME AND BELEN to WILLARD 115 kV line--Voltage Plots





TYP 2016 HW WECC 2015-16 HW2A APPROVED BASE CASE
JANUARY 10, 2011
3-Phase fault at TOME 115 kV bus;
Trip BELEN_PG-TOME Line TOME 115/46 kV transformer in 4 cycles.

Page 1

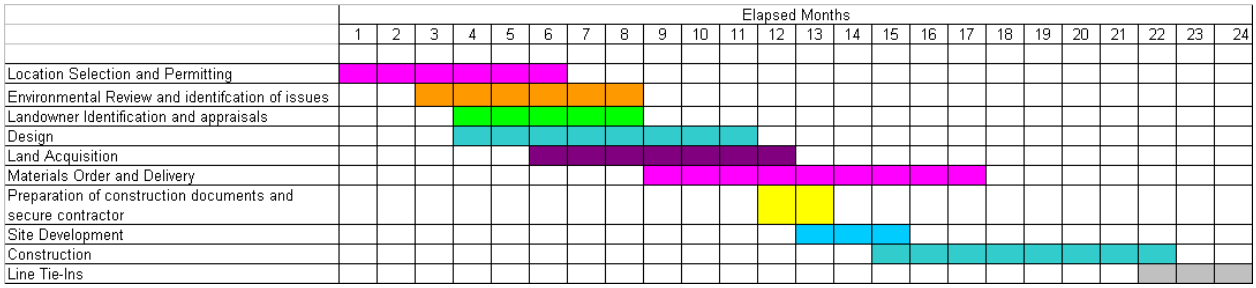
120_hw_sav_post_BELTOMETOMEXFMR.chf

Tue Sep 25 10:29:36 2012

Figure B-20--2015 HW----3 Phase Fault at TOME 115 kV; Open BELEN to TOME AND TOME 115/46 kV transformer--Voltage Plots

13. APPENDIX C: Construction Schedule and Assumptions

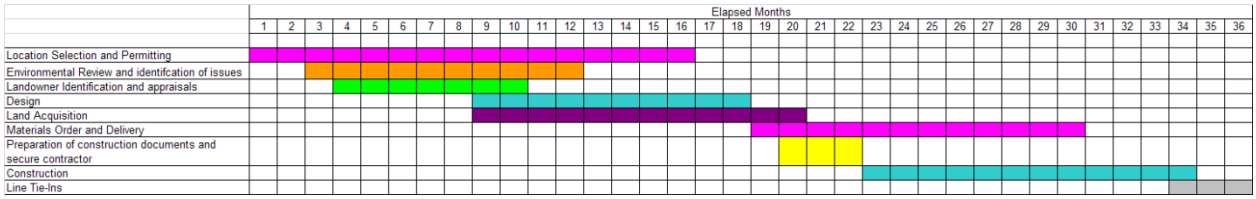
Estimated Station Construction Activity Schedule and Assumptions



Key assumptions:

- **PNM may elect to contract any or all parts of the project.**
- **Environmental estimate based on no significant environmental findings.**
- **Outage coordination for work on and under the AW line or other outages on the system may increase the schedule.**
- **Outages may be restricted to off-peak periods such as spring or fall.**
- **The project schedule is based on having all permits, agreements, and authorizations completed prior to initiation of construction work.**
- **General station pricing based on current equipment standards and standard station design.**
- **Right of Way pricing based on average acre values.**
- **Station design based on 500' x 700' site.**

Estimated Line Construction Activity Schedule and Assumptions



Key assumptions:

- **New line will be constructed using PNM's standard conductor (ACSR 795 Drake) and, subject to design review, will use standard steel poles.**
- **The rating of the line will be 200 MVA.**
- **Estimate assumes new right-of-way is acquired, including permitting.**
- **The final design of this line will evaluate alternate routes.**
- **PNM may elect to contract any or all parts of the project.**

- **The project schedule is based on having all permits, agreements, and authorizations completed prior to initiation of construction work.**
- **No major government permitting or environmental issues are encountered.**
- **A new line (approximately 17 miles) will be built paralleling the existing Algodones-Willard line.**
- **Right-of-way costs will be dependent on several factors including number of owners, owners' willingness to provide land or easement, and the width of needed easement, etc. Where reasonable, PNM will consider utilizing public rights-of-way. Direct purchase of land is estimated at fair market value.**

XXXXX

Lost Horizon 10 MW PV Generation Project

Small Generator Interconnection Feasibility Study

(OASIS # SGI-PNM-2010-03)

October 2010

Prepared by:

Public Service Company of New Mexico Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for XXXXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts.

Any correspondence concerning this document, including technical and commercial questions should be referred to:

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List of Figures, Tables, and Graphs

EXECUTIVE SUMMARY

XXXXX submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 10MW AC to the Public Service of New Mexico ("PNM") distribution primary system. The request is identified as Project Lost Horizon and would be connected to Lost Horizon Feeder 14. An application was submitted based on the PNM's Open Access Transmission Tariff, Small Generator Interconnection Procedures ("SGIP") for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study was performed by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts ("Distribution Planning").

The estimated cost of connecting Project Lost Horizon to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRupter)	$XXXXX	~16 week lead time ~3 Days to build
Interconnection (Line Construction)	$XXXXX	~16 week lead time ~3 weeks to build
PNM metering	$XXXXX	~3 week lead time ~ 4 days to build
Communication	$XXXXX	~16 week lead time ~3 Days to build
TOTAL	**$XXXXX**	**6-7 months for lead time and final build out.**

The application notes the use of the Satcon Power Systems PowerGate 500kW transformerless PV inverters and that this inverter is UL 1741 compliant.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic ("PV") generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is

injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Lost Horizon does not have an adverse impact on the PNM distribution system when operated under normal conditions at a fixed 99% power factor importing VARs. It does have an adverse impact on the PNM distribution system for a loss of Lost Horizon Substation if it is allowed to operate during a loss of Lost Horizon Substation. As a result, Distribution Planning recommends that the facility be completely curtailed until service from Lost Horizon Substation can be restored. The Project location will result in an interconnection with Lost Horizon Feeder 14. The analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds were found not to cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded under normal operating conditions.
5. There are no anticipated issues with operating Project Lost Horizon in conjunction with PNM's RCCS System.
6. The Project contribution to fault current does not adversely impact the protection coordination on the Lost Horizon substation or Lost Horizon Feeder 14 for normal configuration. Additionally, the Project contribution to fault current does not adversely impact the Central substation or Central Feeder 13 protection scheme for contingent configuration.
7. Project output will cause a flow of electricity from the distribution system through the substation transformer, but this is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Lost Horizon and has determined that there are no adverse impacts associated with a 10MW AC source connected to Lost Horizon Substation via Lost Horizon Feeder 14 as long as the system is operated as stated above.

An alternative to requiring that Project Lost Horizon remain out of service for a loss of Lost Horizon Substation would be for PNM to install a new 115 - 12.47kV transformer at Lost Horizon

Substation and extend a dedicated circuit to Project Lost Horizon Substation. This option was not evaluated in this study due to the anticipated high cost of the option.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Lost Horizon Substation is maintained within established PNM voltage, equipment and fault protection criteria.

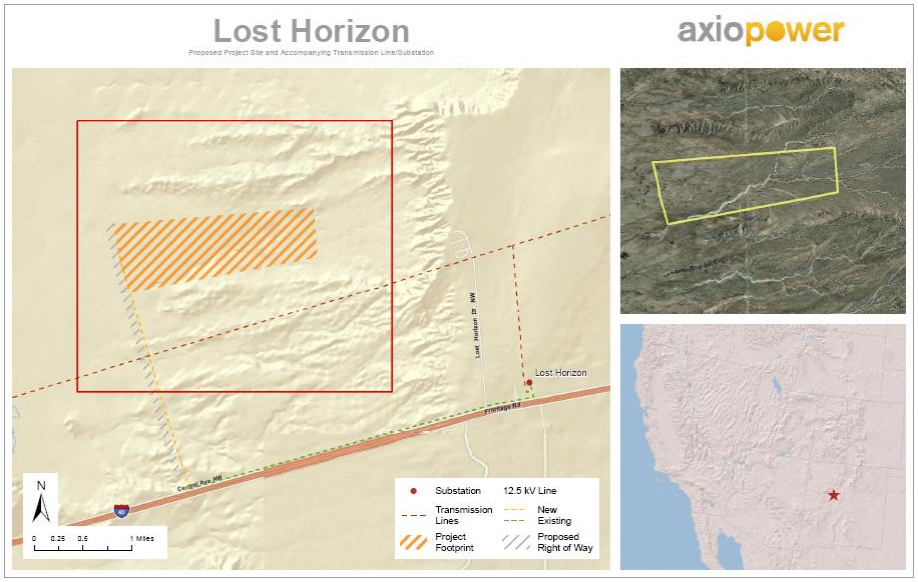
1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic ("PV") electric generation source connected to the distribution primary system identified as Project Lost Horizon. The PV generation source will be connected to the distribution primary using inverters that convert the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Lost Horizon proposes to connect a nominal 10MW AC PV facility to one Lost Horizon Substation Feeder in Albuquerque, NM. The Project will be located west of Lost Horizon Dr. NW and Central Ave NW as shown in Figure 1. The circuit distance from Lost Horizon Substation to the Project Lost Horizon point of interconnection ("POI") is about 15,954 ft.

Figure 1 – Project Lost Horizon Location



3.0 SYSTEM CONFIGURATION

Project Lost Horizon is a large PV source and is proposed to be served by one distribution feeder, Lost Horizon Feeder 14. Lost Horizon Substation presently has four distribution feeders serving load. Study analysis is based on connecting the Project to Lost Horizon Feeder 14. Table 1 shows the rating of Lost Horizon Substation as determined by the EPRI Ptload program.

Table 1 - Substation transformer nameplate versus Ptload rating

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Lost Horizon	33.6	34.36	37.72	115-12.47

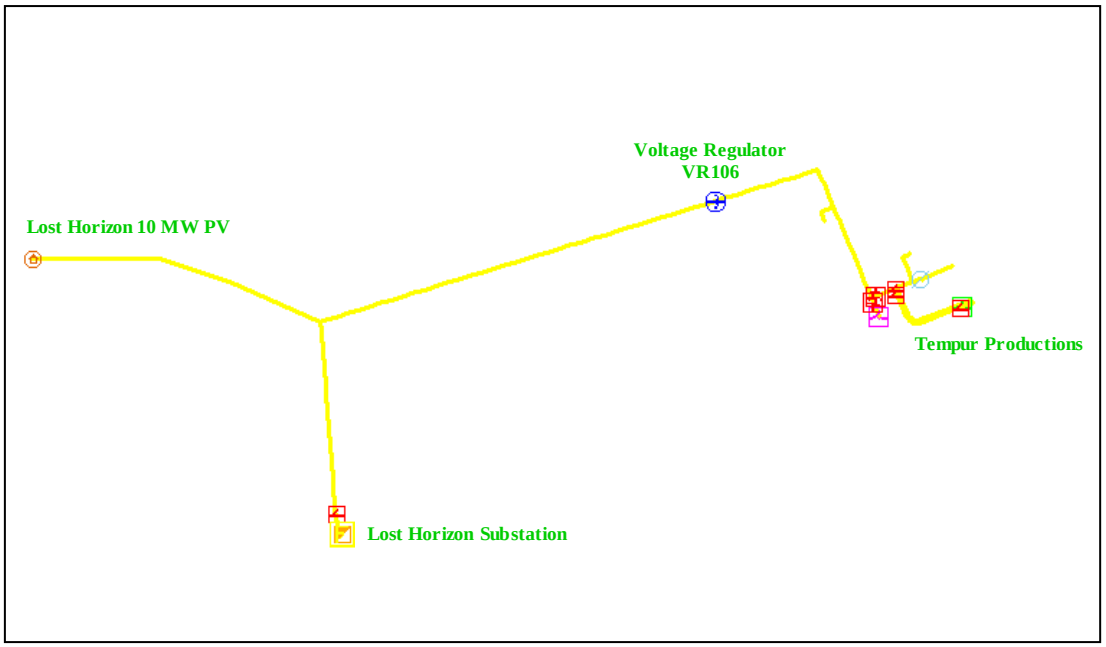
In 2009, PNM's system peak occurred in July. Each year PNM takes a snapshot of its feeder and substation loads in the month of the system peak for planning purposes. Table 2 shows the non-coincident 2009 July peak summer loads for Lost Horizon Substation and feeders.

Table 2 - July 2009 Non-coincident Peak Loads

Feeder	July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Lost Horizon				
Lost Horizon 11	1,830	-510	1,900	-96.3
Lost Horizon 12	3,978	813	4,060	98
Lost Horizon 13	2,584	-291	2,600	-99.4
Lost Horizon 14	2,904	-1,222	3,151	-92.2
Lost Horizon Sub	10,435	-1,479	10,539	-99.0

Figure 2 is a picture of the distribution feeder used in the Advantica SynerGEE modeling program.

Figure 2 – SynerGEE model of Lost Horizon Feeder 14



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The daylight hours maximum and minimum loading on the Lost Horizon Substation and on Lost Horizon Feeder 14 are shown in Tables 3 and 4:

Table 3 – Lost Horizon Substation max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
August 5, 2009	1 PM	10,465	-1,552	10,580	-98.92	509	494	483
May 23, 2009	9 AM	4443	-60	4443	-99.99	220	213	198

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Table 4 – Lost Horizon Feeder 14 max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
August 5, 2009	1 PM	2,903	-1,149	3,122	-92.98	141	139	145
July 18, 2009	7 AM	927	-253	961	-96.47	43	42	45

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Lost Horizon, has a rated output of 10,000 KW. There are four feeders, Lost Horizon Feeders 11, 12, 13, and 14, on Lost Horizon Substation presently serving load. The maximum load on the Lost Horizon Substation transformer, as shown in Table 3, is slightly higher than the rated output of Project Lost Horizon. This may result in electricity flowing from the distribution system through the substation transformer to the transmission system during non-peak load conditions. Of concern are the substation bus voltage and regulation as well as impact on the transmission system.

4.1 Voltage impacts on the transmission system

The minimum load on Lost Horizon Substation during daylight hours is 4,443 kW. The minimum load on the Lost Horizon Substation transformer is less than the rated output of the project with the difference between the maximum Project Lost Horizon generation and the Lost Horizon transformer load being 5,557 kW. Since this is only slightly higher than PNM's threshold of 5 MW, no transmission related issues associated with Project Lost Horizon are anticipated.

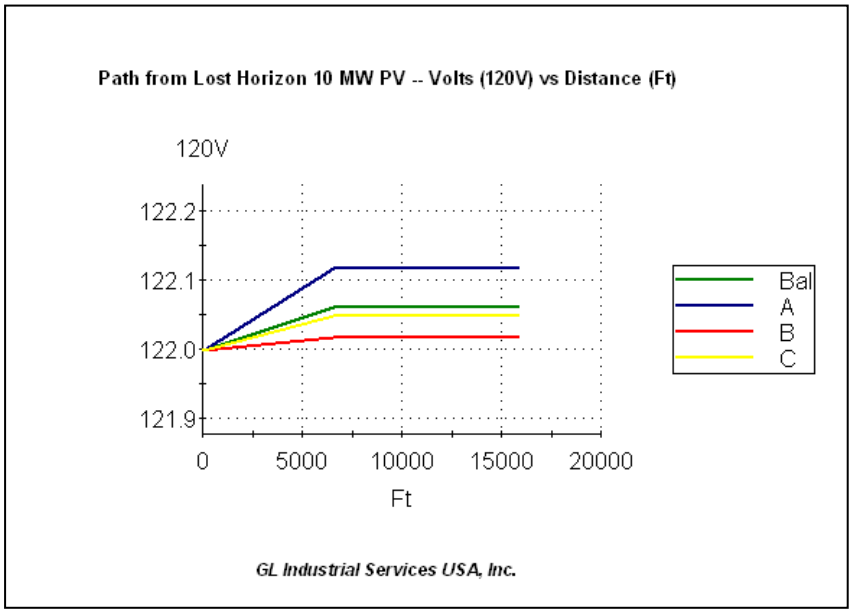
4.2 PV system impacts associated with power factor setting

Scenario's reviewed by this study define an inverter based distributed generation facility operating with a power factor other then unity to be a facility that is absorbing or importing reactive power at the POI. Inverter control systems can be adjusted to allow the PV system to absorb reactive power ("Vars") from the distribution system. Recommendations to absorb reactive power at the POI, to mitigate the Project voltage rise impact on the electric distribution system, may be included in the evaluated operating conditions to review the ability of the facility to maintain ANSI C84.1 criteria limits.

4.3 Voltage impacts for maximum daylight hours load for normal configuration

The Lost Horizon Feeder 14 voltage for the feeder daylight hours maximum load for 2009 with and without Project Lost Horizon, per the Synergee model, are shown in Graphs 1 and 2. The larger customer load on the feeder, Tempur Productions, was modeled using the actual load value from the daylight hours maximum date and time.

Graph 1 – Lost Horizon Feeder 14 voltage drop from Lost Horizon Substation to Project Lost Horizon POI for daylight hours maximum load on August 5, 2009. Project Lost Horizon is OFF.

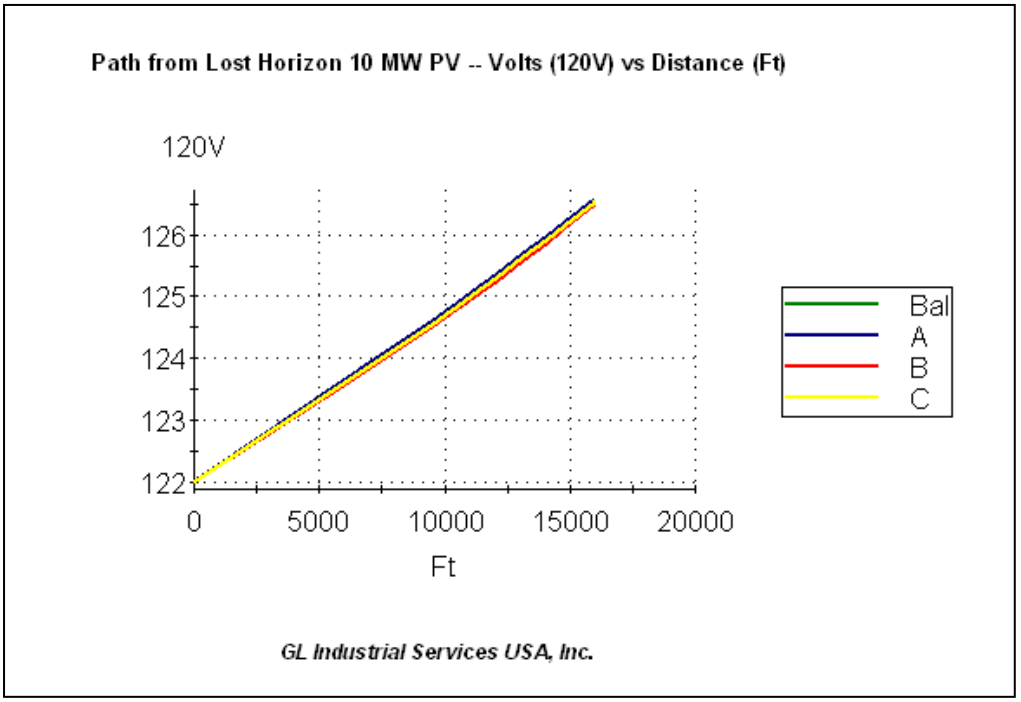


The model voltages at the point of interconnection are:

Phase A – 122.1 volts Phase B – 122.0 volts Phase C – 122.1 volts Balanced – 122.1 volts

The voltages on Lost Horizon Feeder 14 prior to the installation of Project Lost Horizon are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 – Lost Horizon Feeder 14 voltage drop from Lost Horizon Substation to the Lost Horizon 10MW POI for daylight hours maximum load on August 5, 2009. Project Lost Horizon is ON, 100% power factor.

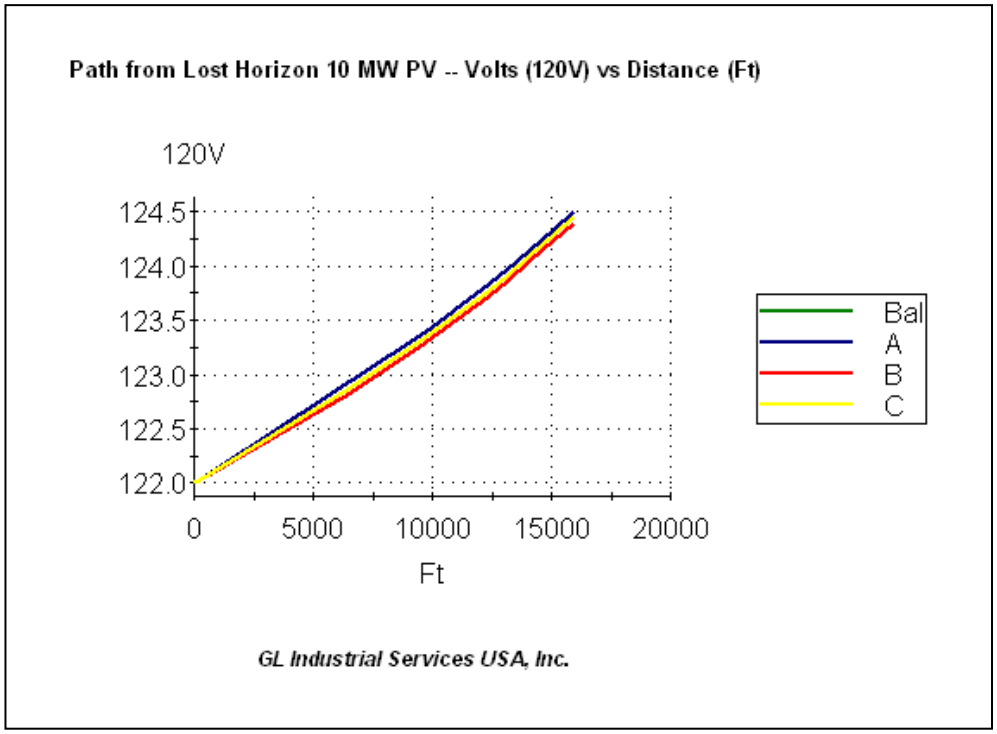


The model voltages at the point of interconnection are:

Phase A – 126.6 volts Phase B – 126.5 volts Phase C – 126.5 volts Balanced – 126.5 volts

The voltages on Lost Horizon Feeder 14 after the installation of Project Lost Horizon operating at 100% power factor are not within the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. Voltage control utilizing power factor correction will be needed during maximum loading timeframes.

Graph 3 – Lost Horizon Feeder 14 voltage drop from Lost Horizon Substation to the Lost Horizon 10MW POI for daylight hours maximum load on August 5, 2009. Project Lost Horizon is ON, Project Lost Horizon at 99% PF Importing VARs.



The model voltages at the point of interconnection are:

Phase A – 124.5 volts Phase B – 124.4 volts Phase C – 124.5 volts Balanced – 124.5 Volts.

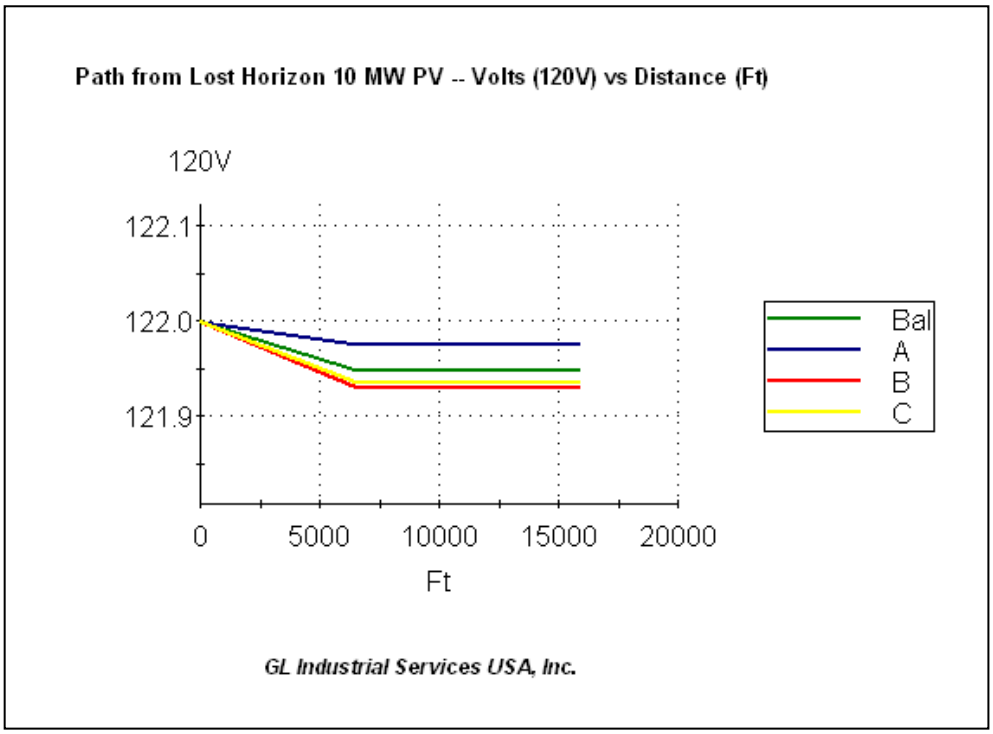
The voltages on Lost Horizon Feeder 14 after the installation of Project Lost Horizon operating at 99% power factor importing VARs are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4 Voltage impacts for minimum daylight hours load for normal configuration

The Lost Horizon Feeder 14 voltage for the feeder daylight hours minimum load for 2009 with and without Project Lost Horizon, per the Synergee model, are shown in Graphs 4, 5 and 6.

The large customer load on the feeder, Tempur Productions, was modeled using the actual load value from the daylight hours minimum date and time.

Graph 4 – Lost Horizon Feeder 14 voltage drop from Lost Horizon Substation to the Project Lost Horizon POI for daylight hours minimum load on July 18, 2009. Project Lost Horizon is OFF.

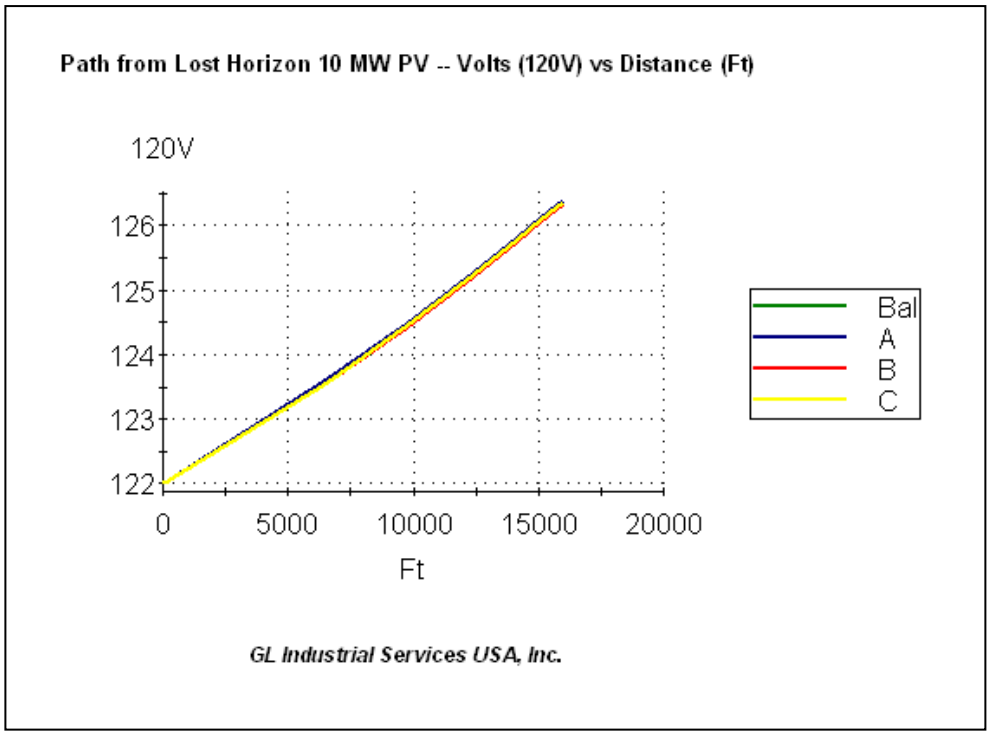


The model voltages at the point of interconnection are:

Phase A – 122.0 volts Phase B – 121.9 volts Phase C – 121.9 volts Balanced – 121.9V

The voltages on Lost Horizon Feeder 14 prior to the installation of Project Lost Horizon are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 5 – Lost Horizon Feeder 14 voltage drop from Lost Horizon Substation to the Project Lost Horizon POI for daylight hours minimum load on July 18, 2009. Project Lost Horizon is ON.

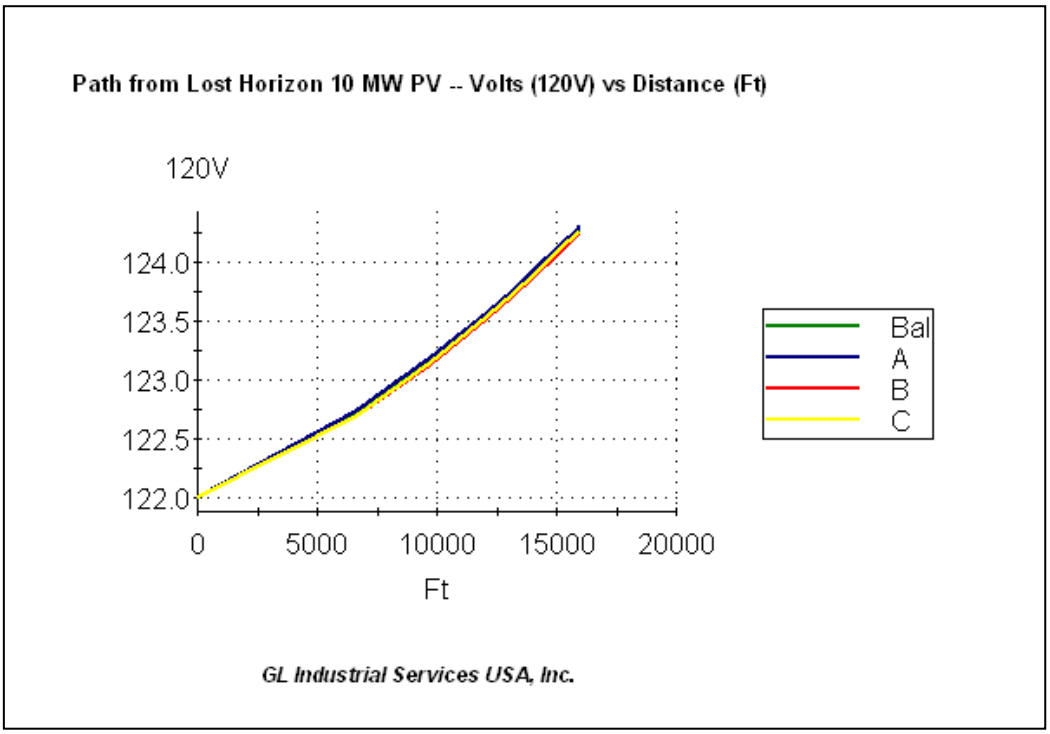


The model voltages at the point of interconnection are:

Phase A – 126.4 volts Phase B – 126.3 volts Phase C – 126.4 volts Balanced – 126.4 Volts.

The voltages on Lost Horizon Feeder 14 after the installation of Project Lost Horizon operating at 100% power factor are not within the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. Voltage control utilizing power factor correction will be needed at minimum loading timeframes.

Graph 6 – Lost Horizon Feeder 14 voltage drop from Lost Horizon Substation to the Project Lost Horizon POI for daylight hours minimum load on July 18, 2009. Project Lost Horizon is ON, Project Lost Horizon at 99% PF Importing VARs.



The model voltages at the point of interconnection are:

Phase A – 124.3 volts Phase B – 124.3 volts Phase C – 124.3 volts Balanced – 124.3 Volts.

The voltages on Lost Horizon Feeder 14 after the installation of Project Lost Horizon operating at 99% power factor importing VARs are within the PNM voltage criteria (ANSI C84.1) at the POI, as shown in Graph 6, and are acceptable.

In conclusion for normal configuration, Project Lost Horizon output does cause the voltage on Lost Horizon Feeder 14 to increase if allowed to operate at 100% power factor. The voltage increase is not acceptable. The voltage stays within the PNM criteria of ANSI C84.1 and is

acceptable if the system operates at 99% power factor importing VARs. The inverter would be operating at 10 MVA, but the real power output is limited to 9.9 MW. The proposed SATCON Power Systems PowerGate 500KW Transformerless PV Inverter is not capable of operating at a power factor less than 100%. An inverter capable of operating at a power factor other than unity will need to be used for this project.

4.5 Voltage impacts for maximum daylight hours load for contingency configuration

Presently, there is one possible scenario for contingency configuration that Project Lost Horizon can contribute to, which is the loss of Lost Horizon Substation.

4.5.1 Contingency configuration – Loss of Lost Horizon Substation, maximum load

For the loss of the Lost Horizon Substation, Lost Horizon Feeders 11, 13, and 14 are transferred to Central Substation through Central Feeder 13. Lost Horizon Feeder 12 must remain out of service for the duration of the Lost Horizon Substation outage due to unacceptably low voltages and problems detecting faults at the end of Lost Horizon 12 when Central Feeder 13 is providing backup service to Lost Horizon 12. To accommodate the Lost Horizon load, 88% of the normal load on Central Feeder 13 is transferred to other area feeders. The daylight hours maximum and minimum loading on the Central Substation, Central Feeder 13, and the Lost Horizon Feeders11, 12, and 13 are shown in Tables 5 and 6. The Synergee contingency model for the loss of Lost Horizon Substation, with and without Project Lost Horizon, was developed using the non-coincident daytime minimum and maximum feeder loads for the circuits involved. Voltages for Central Feeder 13 daylight hours maximum load for 2009 with and without Project Lost Horizon for the loss of Lost Horizon Substation, per the Synergee model, are shown in Graphs 7 through 11. Large customer loads on the feeders, such as Tempur Productions, Bernalillo County Detention Center, and the City of Albuquerque Transit Center, were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from Central Substation to the Project Lost Horizon point of interconnection (POI) is about 53,136 ft. or 10.06 miles.

Figure 3 is a picture of the contingent feeder configuration used in the SynerGEE modeling program with Central Feeder 13 providing backup support to the area for a loss of Lost Horizon Substation.

Figure 3 – SynerGEE model of Central Feeder 13 for a Loss of Lost Horizon Substation

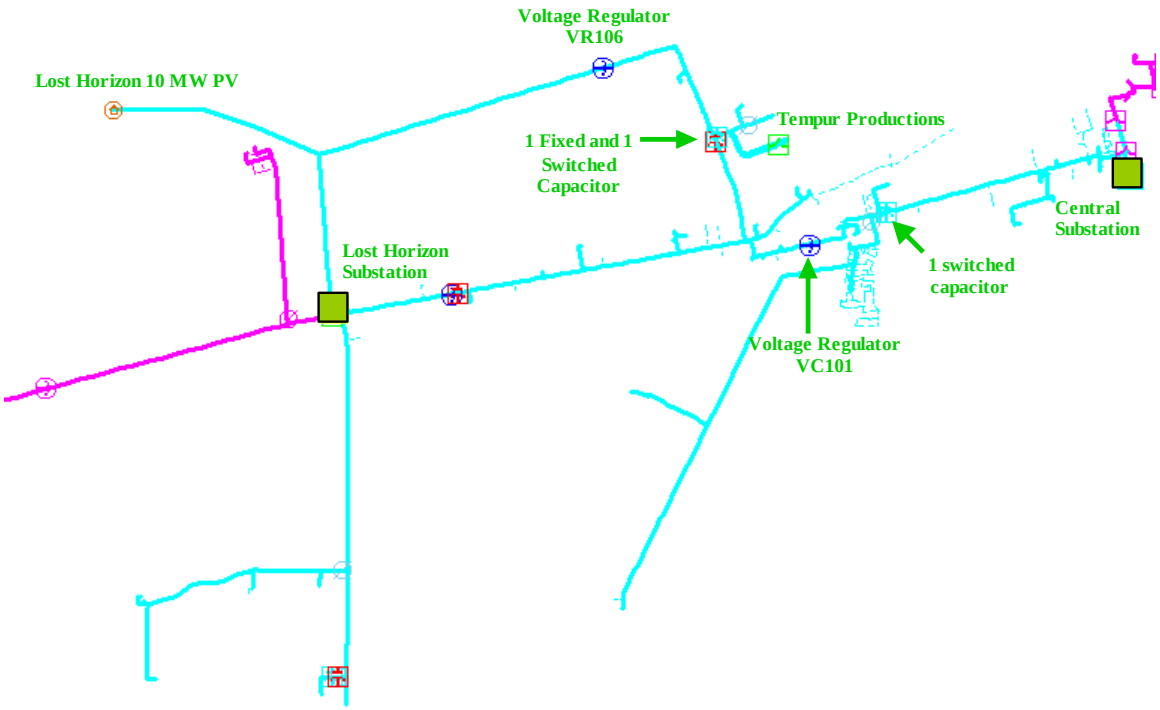


Table 5 – Central Substation max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 13, 2009*	6 PM	21,199	3,502	21,486	98.66	907	922	861
October 4, 2009	7 AM	6458	443	6473	99.77	309	308	287

NOTE: Maximum load was adjusted to reflect a Central 12 to Volcano 23 load transfer.

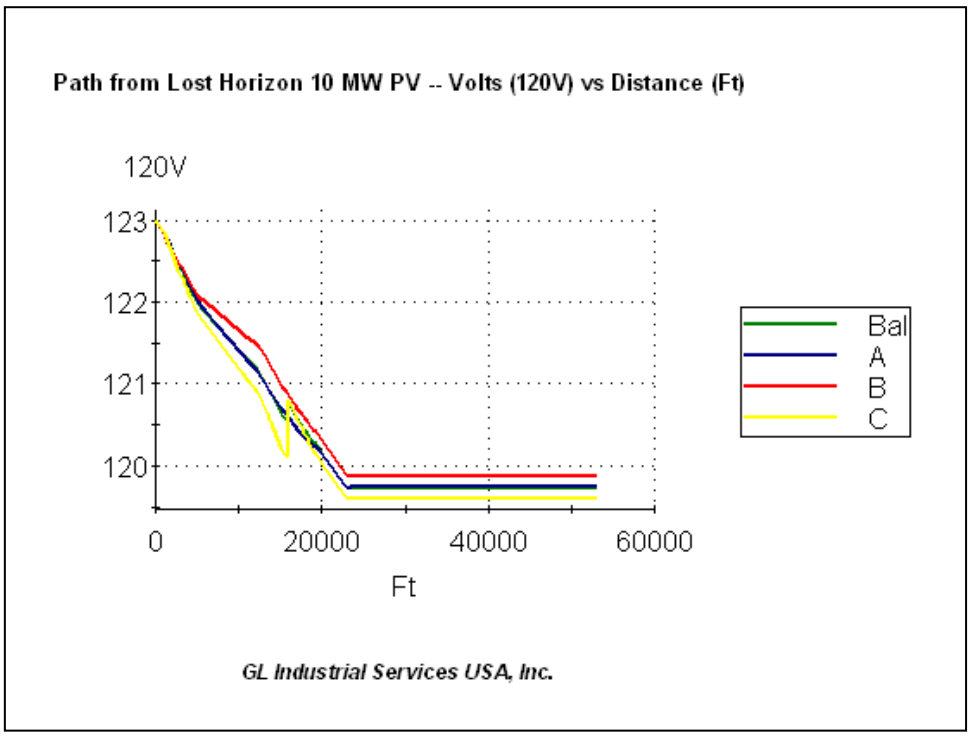
NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Table 6 – Lost Horizon Feeders11, 12, 13 and Central 13 max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Lost Horizon 11								
July 20, 2009	4 PM	1,809	-508	1,879	-96.27	98	85	74
May 31, 2009	7 AM	624	252	673	92.72	36	31	25
Lost Horizon 12								
July 15, 2009	4 PM	3,978	813	4,060	97.98	188	181	179
November 3, 2009	7 AM	1,919	-444	1,970	-97.43	95	89	86
Lost Horizon 13								
August 4, 2009	1 PM	2,573	-352	2,597	-99.08	117	118	116
May 23, 2009	5 PM	1,015	663	1,213	83.72	55	56	56
Central 13								
August 18, 2009	3 PM	3,873	-390	3,892	-99.50	171	157	193
May 24, 2009	7 AM	1393	306	1426	97.67	63	58	70

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Graph 7 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours maximum loads. Project Lost Horizon is OFF.

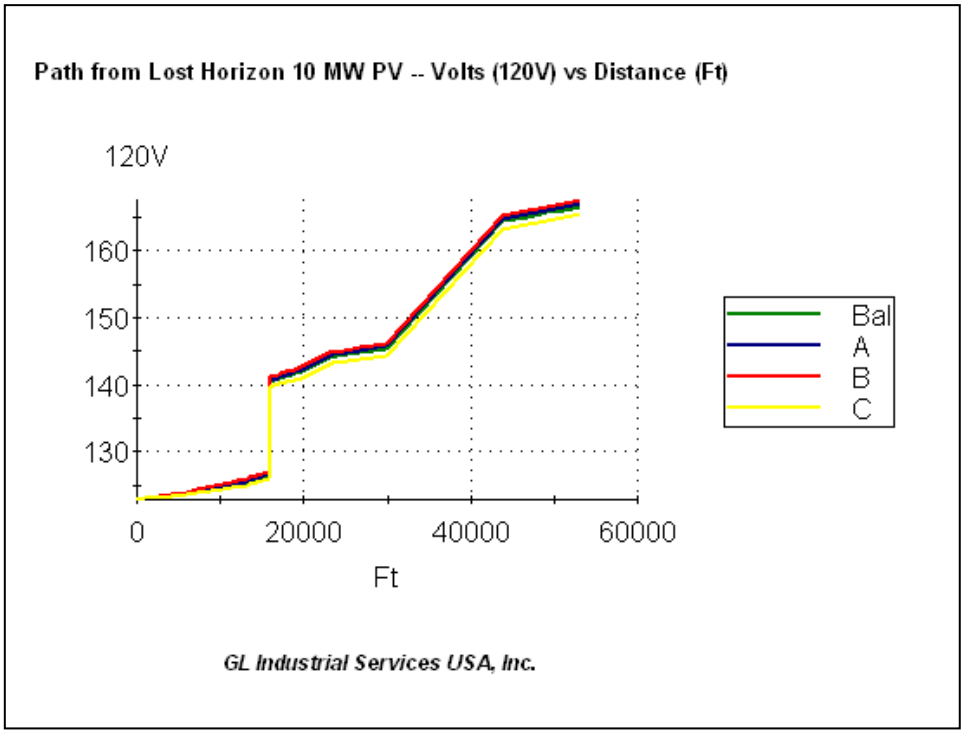


The model voltages at the point of interconnection are:

Phase A – 119.7 volts Phase B – 119.9 volts Phase C – 119.6 volts Balanced – 119.7 volts.

The voltages on Central Feeder 13 for the loss of Lost Horizon Substation prior to the installation of Project Lost Horizon are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable.

Graph 8 -Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours maximum loads. Project Lost Horizon is ON, at 100% power factor.



The model voltages at the point of interconnection are:

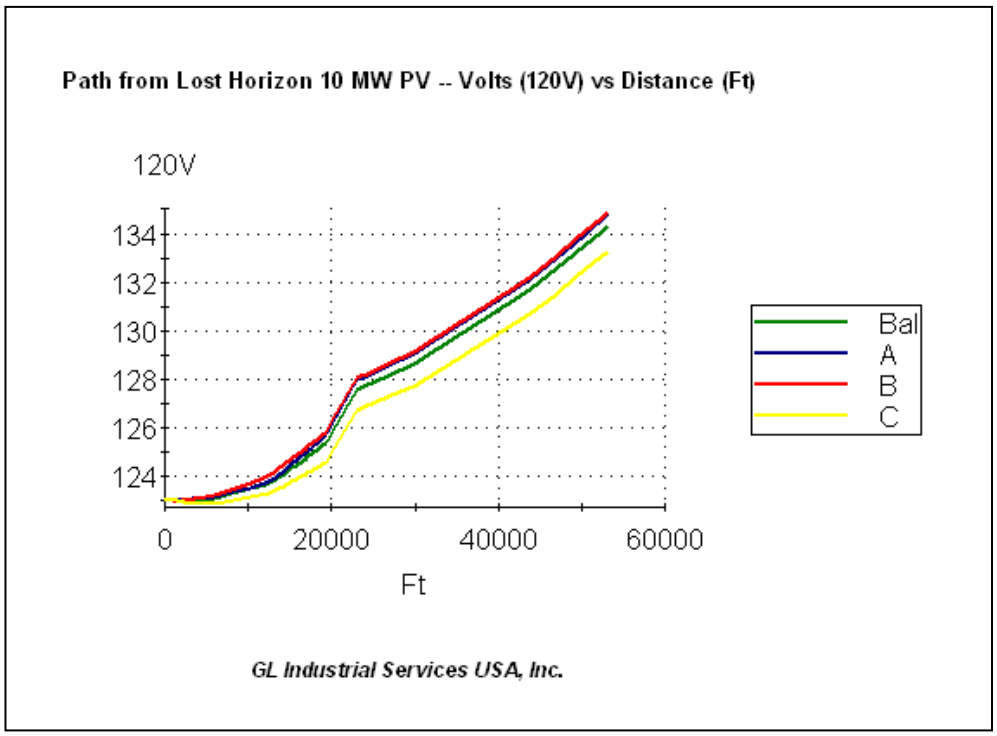
Phase A – 166.9 volts Phase B – 167.4 volts Phase C – 165.3 volts Balanced – 166.6 volts.

The voltages on Central Feeder 13 for the loss of Lost Horizon Substation with Project Lost Horizon operating are not within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are not acceptable. While Central Feeder 13 is providing backup support to the area, there are two voltage regulators in the path between Project Lost Horizon and the backup Central Substation. Voltage regulator VR106, normally on Lost Horizon Feeder 14, is set in the bi-directional mode. Voltage regulator VC101, normally on Lost Horizon Feeder 11, is also set in the bi-directional mode to regulate the voltage west of its location when Central Feeder 13 is serving the area. When Project Lost Horizon is on during the contingent configuration, the photovoltaic generation is larger than the maximum load on Central Feeder 13. The power flows from Project Lost

Horizon through VR106, through VC101, to Central Substation. As mentioned above, VR106 is set in bi-directional mode. However, with Project Lost Horizon on, the current flow in the regulator is still from west to east, which is the normal forward direction for the regulator. VC101 tries to lower the voltage on the Central Substation side of the regulator. It senses that the voltage on the Central Substation side of the regulator is higher than its voltage setting and taps down to its minimum tap (16 lower) in an attempt to lower the voltage on the Central Substation side of the regulator. Since the voltage at Central Substation is essentially fixed, the net effect is to raise the voltage on the Lost Horizon 10MW side of VC101. VR106 is also in bi-directional mode with the current flow in the normal west to east direction with Project Lost Horizon on. VR106 senses high voltage on its load side and taps down to its minimum tap (16 lower) in an attempt to lower the load side voltage. However, the voltage on the Central substation side of the voltage regulator is essentially fixed; the net effect is to further raise the voltage on the Project Lost Horizon side of VR106. With the present regulation settings and with Project Lost Horizon in service, Synergee calculations indicate that the two voltage regulators in series contribute to raising the voltage to almost 167 volts balanced at the POI. Calculated voltages of 167 volts (140% of nominal) exceed voltage criteria for the inverter(s) at Project Lost Horizon and PNM assumes that the facility would shut down once the inverters sense voltage above 10% of their nominal rating. PNM voltage criteria (ANSI C84.1) at the POI would be above 5% of nominal, which is not acceptable.

Graph 9 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours maximum load. Project Lost Horizon is ON, at 100% power factor.

Voltage Regulators VR106 and VC101 OFF.



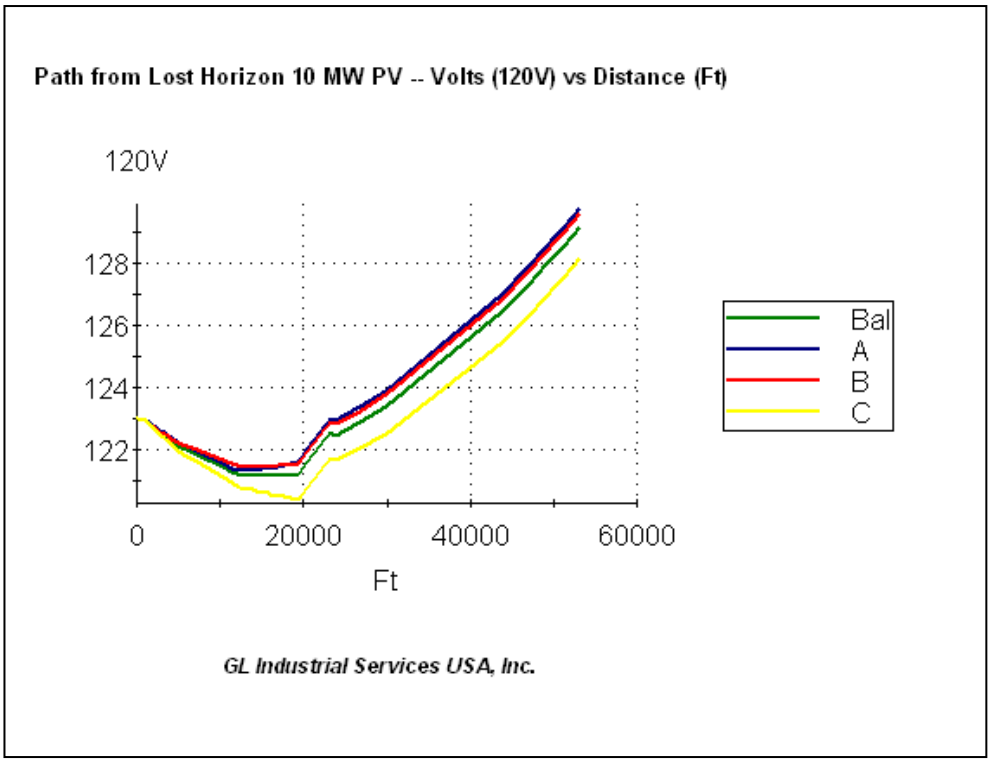
The model voltages at the point of interconnection are:

Phase A – 134.8 volts Phase B – 134.9 volts Phase C – 133.3 volts Balanced – 134.3 volts.

Both voltage regulators need to remain in service to provide voltage support in the area when Project Lost Horizon is off. However, turning both regulators off when Project Lost Horizon is on reduces the voltage at the POI to 134.3V balanced. This is an improvement but is still not an acceptable voltage level.

Graph 10 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours maximum load. Project Lost Horizon is ON, at 100% power factor.

Voltage Regulators VR106 and VC101 OFF
Capacitor C1150 OFF



The model voltages at the point of interconnection are:

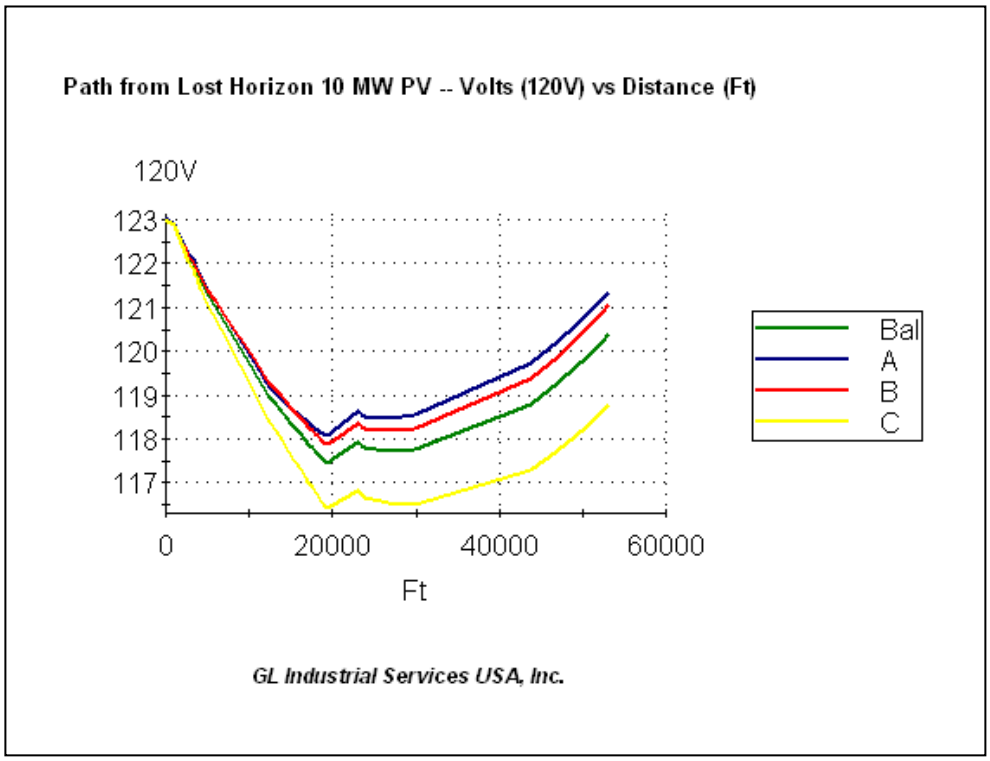
Phase A – 129.8 volts Phase B – 129.6 volts Phase C – 128.1 volts Balanced – 129.2 volts.

Turning capacitor C1150 off in addition to having voltage regulators VR106 and VC 101 off, improves the voltage further but the voltages are still not within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are not acceptable. Running Project Lost Horizon at other than unity power factor is needed to reduce the voltages to within (ANSI C84.1 Range B)

Graph 11 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours maximum load. Project Lost Horizon is ON,

Voltage Regulators VR106 and VC101 OFF, Capacitor C1150 OFF,

Project Lost Horizon at 99% PF Importing VARs.



The model voltages at the point of interconnection are:

Phase A – 121.4 volts Phase B – 121.1 volts Phase C – 118.8 volts Balanced – 120.4 volts.

The voltages on Central Feeder 13 for the loss of Lost Horizon Substation with Project Lost Horizon on and operating at a 99% power factor importing VARs are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. During a Lost Horizon Substation outage while the area is in a contingent feeder configuration, voltage regulators VR106 and VC101 and capacitor C1150 must be turned off and Project Lost Horizon must operate at 99% Power Factor importing VARs to avoid severe over-voltage at the POI and on other locations on PNM's

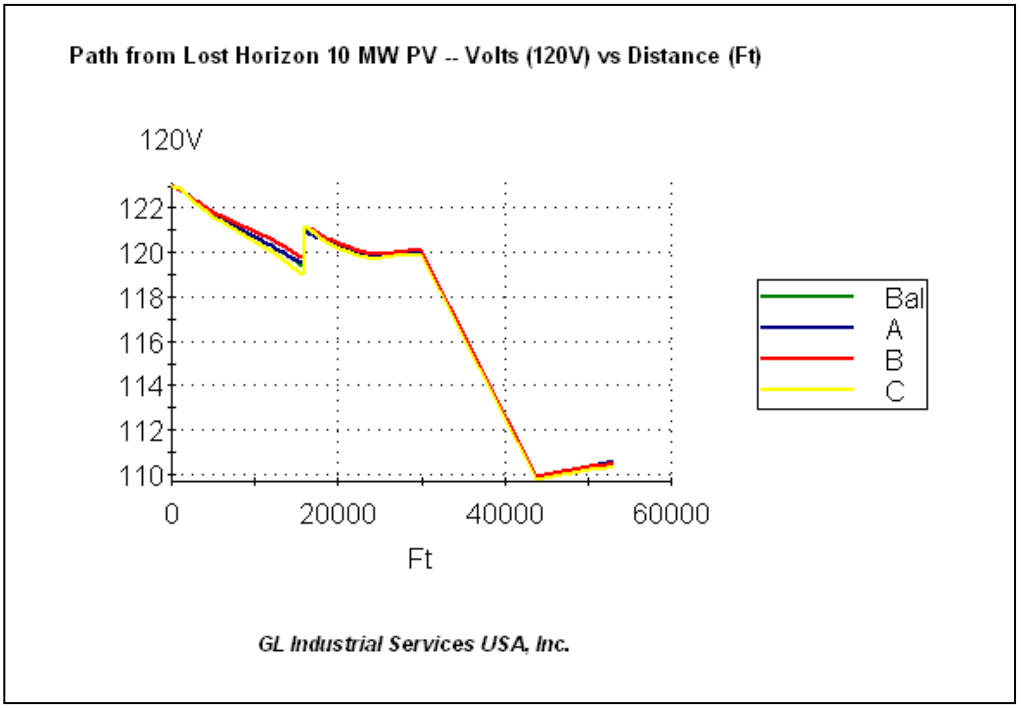
distribution system. Note that with this configuration, Central Feeder 13 is operating with a –10% Power Factor.

Voltage regulator VC101 has remote control capability and remote control could be added to VR106. However, turning off VC101 andVR106 before restoring service through Central Feeder 13 would be a human operator function that would need to be written into the Lost Horizon Substation outage procedure. Although this could be done, there is a risk that this procedural step could be missed or completed out of sequence. Given the automatic operation of the PV inverters, this solution is not recommended. When the PV inverters at Project Lost Horizon sense the return of the reference voltage from PNM, the inverters will start to operate. PNM cannot guarantee that the voltage regulators will be turned off at the appropriate time to avoid high voltage. As a result, the output from Project Lost Horizon must be limited to a level that does not cause voltages issues when both VC101 and VR106 are in service. Therefore, the maximum output from Project Lost Horizon was determined for the minimum daytime load when the risk of over voltage is highest (Reference section 4.5.2). That allowable output level was then modeled for the maximum daytime load. The maximum output allowable for the minimum daytime load was determined to be Project Lost Horizon operating at 30% of its rated output at a 99% power factor importing VARs. Capacitor C1150 was also modeled off to keep the voltages within range. The results are shown below.

Graph 12 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours maximum load. Project Lost Horizon is ON at 30% of rated output,

Capacitor C1150 OFF, Voltage Regulator VR106 is ON VC101 is ON

Project Lost Horizon at 99% PF Importing VARs.



The model voltages at the point of interconnection are:

Phase A – 110.6 volts Phase B – 110.5 volts Phase C – 110.4 volts Balanced – 110.5 volts.

The voltages on Central Feeder 13 for the loss of Lost Horizon Substation with Project Lost Horizon on and limited to operating at 30% of its rated output and a 99% power factor importing VARs are within PNM voltage criteria (ANSI C84.1 Range B) at all of PNM's existing customer locations and are acceptable at those locations. However, the voltage at the Project Lost Horizon POI could be as low as 110.5V balanced, which is not acceptable. PNM's understanding is that PV inverters can operate at +/-10% of the AC voltage setpoint and that the calculated voltage levels should be a sufficient voltage to allow Project Lost Horizon to operate

at 30% output but any future load west of VR106 would be at risk of severely low voltage conditions.

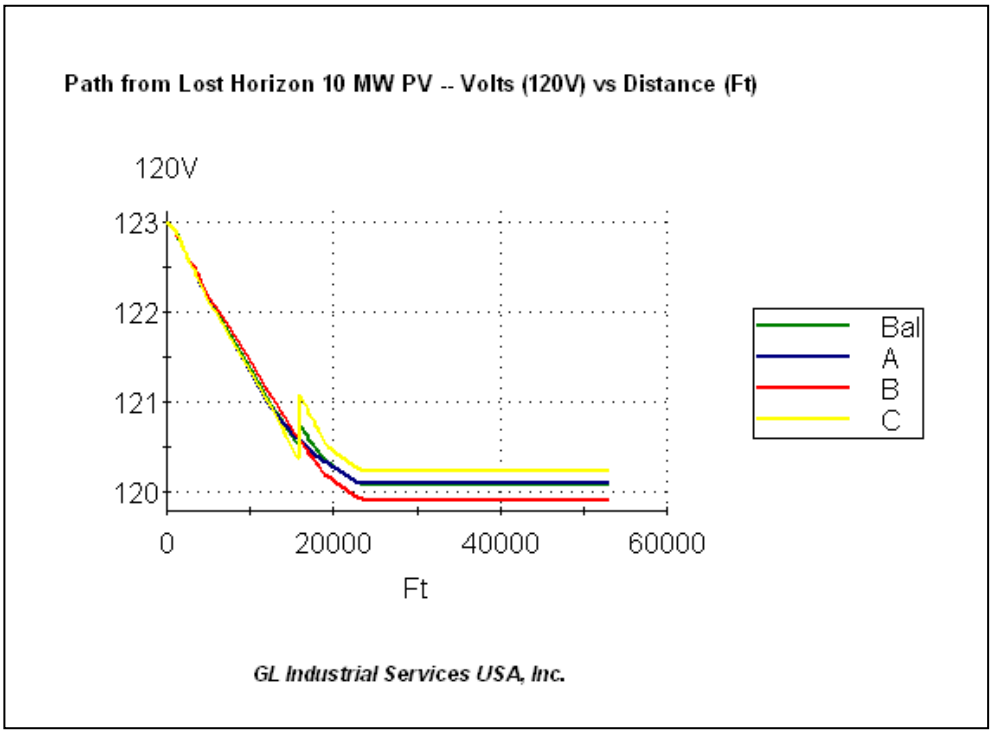
The alternative to operating with the low reference voltage and at 30% output is that Project Lost Horizon can remain out of service until Lost Horizon Substation is back in service and Lost Horizon Feeder 14 can be re-energized in its normal configuration.

4.5.2 Contingency configuration – Loss of Lost Horizon Substation, minimum load

For the loss of Lost Horizon Substation during minimum load conditions, the backup feeder configuration is the same as for maximum load conditions. Central Feeder 13 is the backup feeder to the area. However, for the minimum load scenario, capacitor C1150 is already off, VR106 and VC101 are in service.

Graph 13 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours minimum loads. Project Lost Horizon is OFF.

Capacitor C1150 OFF, VR106 is ON, VC101 is ON



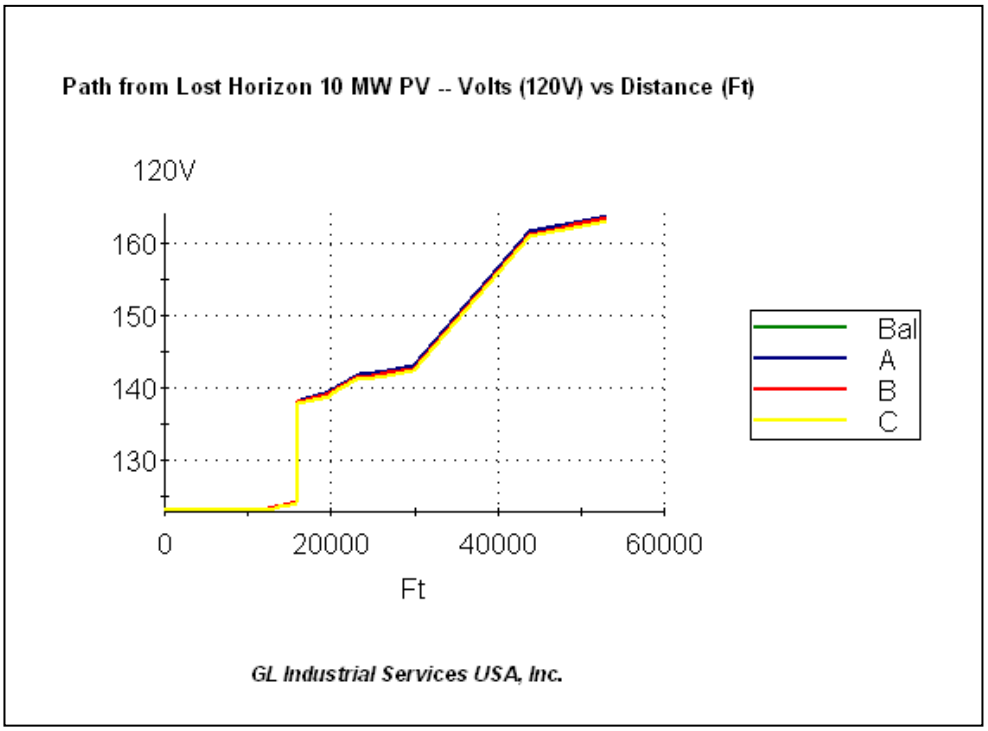
The model voltages at the point of interconnection are:

Phase A – 120.1 volts Phase B – 119.9 volts Phase C – 120.2 volts Balanced – 120.1 volts.

The voltages on Central Feeder 13 for the loss of Lost Horizon Substation prior to the installation of Project Lost Horizon are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable.

Graph 14 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours minimum load. Project Lost Horizon is ON at 100% power factor.

Capacitor C1150 OFF, VR106 is ON, VC101 is ON



The model voltages at the point of interconnection are:

Phase A – 164.0 volts Phase B – 163.6 volts Phase C – 163.2 volts Balanced – 163.6 volts.

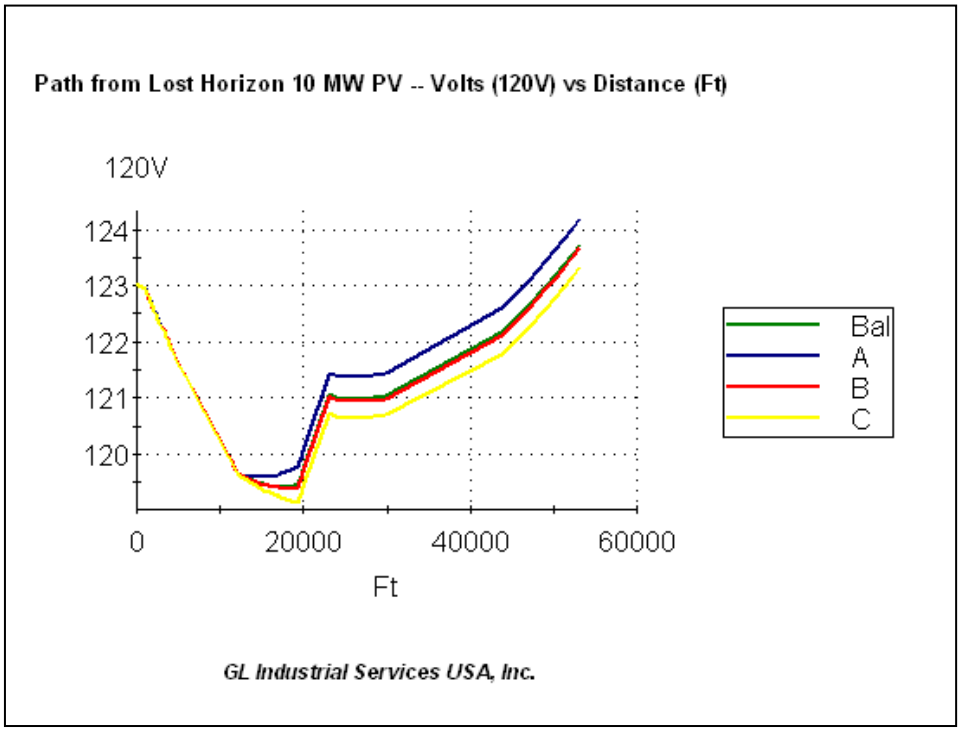
With Project Lost Horizon on, calculated voltages on Central Feeder 13 for the loss of Lost Horizon Substation are not within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are not acceptable. Again under minimum load conditions, the two voltage regulators, VR106 and VC101 are contributing to severe high voltage at the POI. To reduce the voltage, the initial solution to the maximum load case was modeled for minimum load. Both voltage regulators

were turned off and Project Lost Horizon was modeled to run at 99% power factor importing VARs.

Graph 15 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours minimum load. Project Lost Horizon is ON,

Voltage Regulators VR106 and VR101 OFF, Capacitor C1150 OFF,

Project Lost Horizon at 99% PF Importing VARs.



The model voltages at the point of interconnection are:

Phase A – 124.3 volts Phase B – 123.8 volts Phase C – 123.4 volts Balanced – 123.8 volts

The voltages on Central Feeder 13 for the loss of Lost Horizon Substation with Project Lost Horizon on and operating at a 99% power factor importing VARs are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. During a Lost Horizon Substation outage while the area is in a contingent feeder configuration, voltage regulators VR106 and VC101 and capacitor C1150 must be turned off and Project Lost Horizon must operate at 99% Power

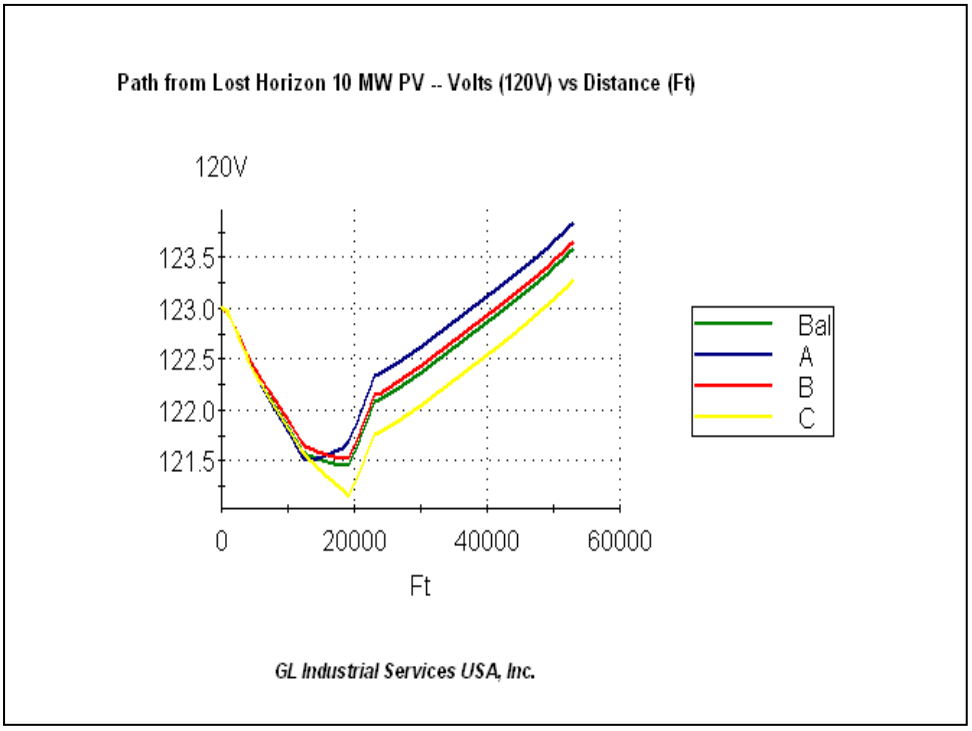
Factor importing VARs to avoid severe over-voltage at the POI and on other locations on PNM's distribution system. Note that with this configuration, Central Feeder 13 is operating with a –68% Power Factor.

Voltage regulator VC101 has remote control capability and remote control could be added to VR106. However, turning off VC101 andVR106 before restoring service through Central Feeder 13 would be a human operator function that would need to be written into the Lost Horizon Substation outage procedure. Although this could be done, there is a risk that this procedural step could be missed or completed out of sequence. Given the automatic operation of the PV inverters, this solution is not recommended. When the PV inverters at Project Lost Horizon sense the return of the reference voltage from PNM, the inverters will start to operate. PNM cannot guarantee that the voltage regulators will be or can be turned off at the appropriate time to avoid high voltage. As a result, the output from Project Lost Horizon must be limited to a level that does not cause voltages issues when both VC101 and VR106 are in service. Therefore, the maximum output from Project Lost Horizon was determined for the minimum daytime load when the risk of high voltage is highest. That allowable output level was then modeled for the maximum daytime load (See Section 4.5.1). The maximum output level allowable for the minimum daytime load was determined to be Project Lost Horizon operating at 30% of its rated output at a 99% power factor importing VARs. Capacitor C1150 was also modeled off to keep the voltages within range. The results are shown below.

Graph 16 - Central Feeder 13 voltage drop from Central Substation to the Project Lost Horizon POI for daylight hours minimum load. Project Lost Horizon is ON at 30% of rated output,

Capacitor C1150 OFF, Voltage Regulator VR106 ON, VC101 is ON

Project Lost Horizon at 99% PF Importing VARs.



The model voltages at the point of interconnection are:

Phase A – 123.9 volts Phase B – 123.7 volts Phase C – 123.3 volts Balanced – 123.6 volts

The voltages on Central Feeder 13 for the loss of Lost Horizon Substation with Project Lost Horizon on and limited to operating at 30% of its rated output and a 99% power factor importing VARs are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. During a Lost Horizon Substation outage while the area is in a contingent feeder configuration, capacitor C1150 must be turned off and Project Lost Horizon must limit its operation to 30% of its rated output and 99% Power Factor importing VARs to avoid severe over-voltage at the POI

and on other locations on PNM's distribution system. Note that with this configuration, Central Feeder 13 is operating with a 7% Power Factor.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Lost Horizon is served by Lost Horizon Feeder 14, and there is one voltage regulator installed on the feeder. The substation LTC is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 120.5 volts and will reduce the voltage if the substation bus is above 123.5 volts.

There is also a voltage regulator, VR106, on Lost Horizon Feeder 14. The regulator is set in the "Bi-directional" mode. VR106 is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts) for both forward and reverse operation. When operating in the normal forward direction, it will operate to boost the voltage if the voltage at the load side terminals of the regulator is below 120.5 volts and will reduce the voltage if the voltage at the load side terminals of the regulator is above 123.5 volts. When operating in the reverse direction, it will operate to boost the voltage if the voltage at the Lost Horizon side terminals of the regulator is below 120.5 volts and will reduce the voltage if the voltage at the Lost Horizon side terminals of the regulator is above 123.5 volts

As seen in Tables 7-12, the Synergee modeling shows the substation transformer LTC changed 1 position for a 10,000 KW source on Lost Horizon Feeder 14 for high or low load periods. This LTC operation is not considered an adverse impact.

Table 7 – Lost Horizon Substation with Project Lost Horizon OFF for daylight hours maximum load

	LOST HORIZON SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.2	122.2	122.2	122.2
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 7. The voltages at Lost Horizon Substation prior to the installation of Project Lost Horizon are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8 – Lost Horizon Substation with Project Lost Horizon ON at 100% PF for daylight hours maximum load

	LOST HORIZON SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.2	122.2	122.1	122.2
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 8. The voltages at Lost Horizon Substation after the installation of Project Lost Horizon are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 9 – Lost Horizon Substation with Project Lost Horizon ON, at 99% power factor importing VARs for daylight hours maximum load

	Lost Horizon SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.4	121.4	121.4	121.4
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 9. The voltages at Lost Horizon Substation after to the installation of Project Lost Horizon running at 99% power factor importing VARs are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The Lost Horizon Feeder 14 voltage for the feeder minimum daylight hours load for 2009 with and without Project Lost Horizon, per the Synergee model, are shown in Tables 10, 11 and 12.

Table 10 – Lost Horizon Substation with Project Lost Horizon OFF for daylight hours minimum load

	LOST HORIZON SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.7	121.7	121.8	121.7
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 10. The voltages at Lost Horizon Substation prior to the installation of Project Lost Horizon are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable. The minimum load was modeled with the 1,800 KVAR capacitor bank on Lost Horizon 14 de-energized.

Table 11 – Lost Horizon Substation with Project Lost Horizon ON, at 100% power factor for daylight hours minimum load

	LOST HORIZON SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.4	121.4	121.5	121.4
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 11. The voltages at Lost Horizon Substation after to the installation of Project Lost Horizon at 100% power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable. The minimum load was modeled with the 1,800 KVAR capacitor bank on Lost Horizon 14 de-energized.

Table 12 – Lost Horizon Substation with Project Lost Horizon ON, at 99% power factor importing VARs for daylight hours minimum load

	LOST HORIZON SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.1	121.1	121.1	121.1
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 12. The voltages at Lost Horizon Substation after to the installation of Project Lost Horizon at 99% lagging power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable. The minimum load was modeled with the 1,800 KVAR capacitor bank on Lost Horizon 14 de-energized.

In conclusion, the voltage on Lost Horizon Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of the Project Lost Horizon output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus borderline of visibility and borderline of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. The voltage regulation equipment installed on a distribution system cannot compensate for a rapid change in load. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given that the amount of PV system output reduction due to clouds is not known, the assumption is that the output goes to zero when a cloud passes over and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Lost Horizon Substation bus was fixed at 122 volts with and without Project Lost Horizon output for maximum and minimum load periods. Table 13 summarizes the balanced voltage and the calculated voltage flicker at the Project Lost Horizon POI. Table 14 is based on the GE flicker graph.

Table 13 - Voltage Flicker at the Project POI due to Project Lost Horizon

	Project Lost Horizon Voltage at POI	
	Minimum Load	**Maximum Load**
Without Project	121.9	122.1
With Project at 99% PF importing VARs	124.3	124.5
% Voltage Flicker	**1.97**	**1.97**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 14 - Frequency of voltage flicker due to PV output changes

% Voltage Flicker	**Fluctuations Based on GE Flicker Curve**	
	Border Line of Visibility	**Border Line of Irritation**
1.97	2/hour	40/hour
1.97	2/hour	40/hour

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

The PV output will vary rather than spike between on and off thus Table 13 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 13. Results are less than the 6% voltage flicker criteria; therefore distribution voltage flicker resulting from changes in Project Lost Horizon output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Lost Horizon POI to the substation were reviewed using the Synergee feeder model with and without Project Lost Horizon's maximum output of 10,000 KW AC.

There were no conductor loading problems from the POI to the substation on Lost Horizon Feeder 14 with Project Lost Horizon OFF. However, with Project Lost Horizon at maximum output when Central Feeder 13 is serving the area for a loss of Lost Horizon Substation during maximum and minimum load conditions, there were conductor loading problems on approximately 3,919 ft. of 2/0 ACSR, which is rated 280 amps for normal and emergency conditions. The Synergee model showed the section loads with Project Lost Horizon running at 99% Power Factor importing VARs during minimum load conditions as A-phase – 405 amps, B-phase – 407 amps and C-phase -406 amps. These sections of 2/0 ACSR would need to be reconductored with 397 AAC as part of the line extension to connect Project Lost Horizon to the feeder if the Project were allowed to operate at full output during a loss of Lost Horizon Substation. However, the study found that Project Lost Horizon must be limited to 30% of its rated output or curtailed completely while Central Feeder 13 is providing backup support to the area for the loss of Lost Horizon Substation. With the Project operating at 30% of its rated output during this contingent condition, the 2/0 ACSR section is not overloaded and does not need to be upgraded.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to

determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. For this study, Project Lost Horizon was found to cause adverse impacts on the system when operating at 100% power factor. The proposed SATCON Power Systems PowerGate 500KW Transformerless PV Inverter is not capable of operating at a power factor less than 100%. An inverter capable of operating at a power factor other than unity will need to be used for this project. When the facility is operating, even with an inverter with variable power factor capability, the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Lost Horizon Feeder 14 has one 1,800 KVAR RCCS controlled capacitor bank and one 600 KVAR fixed capacitor bank. The August 5, 2009 daylight hours peak load on the feeder was 2,903 KW – j1,149 KVAR or 3,122 KVA at a 92.98% leading power factor. Both the switched capacitor and the fixed capacitor were energized during the peak load period. The Synergee model shows the 2009 load is 2,892 KW – 1,144 KVAR or 3,110 KVA at a 93% leading power factor with the capacitor banks energized so the model correlates to the measured load. Project Lost Horizon operating at 99% power factor would change the apparent feeder loading to -6,692 KW + j1,122 KVAR or 6785 KVA at a 99% leading power factor (–99%PF). The positive kVAR indicate that Lost Horizon Feeder 14 is exporting VARs to Project Lost Horizon. This power factor value is within the RCCS power factor control range, but since the single switched capacitor on the circuit is already energized prior to switching Project Lost Horizon on, no additional capacitance would be switched on so there are no over voltage issues caused by RCCS control. Should the RCCS system switch the 1,800 KVAR capacitor off, the minimum voltage on the circuit drops to 119.29V, which is acceptable. There are no issues associated with operating Project Lost Horizon in conjunction with PNM's RCCS System during maximum load conditions. The power factor does change when the PV system is operating, but the Synergee model shows that there are no voltage problems. The thermal problems are addressed in the Feeder Loading section below.

This study also examined switching RCCS controlled capacitor banks under minimum load conditions to see what affect this would have on the system with the inverter operating at both 99% power factor importing VARs and 100% power factor. At minimum feeder load, with the

RCCS controlled capacitor bank offline and Project Lost Horizon operating at 100% power factor, the voltage on the feeder exceeded the PNM criteria of ANSI C84.1. Therefore, voltage control utilizing power factor correction will be needed. With Project Lost Horizon operating at 99% importing VARs and the RCCS controlled capacitor bank offline, the feeder voltage was within the PNM criteria of ANSI C84.1 and was acceptable. At minimum feeder load, with the RCCS controlled capacitor bank online and Project Lost Horizon operating at 99% power factor importing VARs, the feeder voltage negligibly exceeded the PNM criteria of ANSI C84.1 at 126.13V. Since switching the 1,800 KVAR capacitor bank on during minimum load conditions is highly unlikely due to the fact that Synergee shows the feeder power factor at 100%, operating Project Lost Horizon at 99% power factor importing VARs should suffice to protect from high voltage conditions.

For the loss of Lost Horizon Substation while Central Feeder 13 is providing backup support to the area, there are four 1,800 KVAR and one 1,200 KVAR RCCS controlled capacitor banks and one 600 KVAR fixed capacitor bank on Central Feeder 13. There are two 1,800 RCCS controlled capacitor banks and the one 600 KVAR fixed capacitor bank between Project Lost Horizon and Central Substation. During the contingency analysis for the loss of Lost Horizon Substation, the status of each capacitor bank was modeled according to its status shown in the RCCS system at the time of the daytime peak or minimum load. Initially for the feeder daytime maximum load, the 1800 KVAR capacitor bank closest to Central Substation was off, and the 1800 KVAR capacitor bank closest to Project Lost Horizon was on. As discussed in the contingency voltage analysis, the 1,800 KVAR capacitor bank closest to Project Lost Horizon must be off to keep voltages within PNM's acceptable voltage range. With both RCCS controlled capacitors off, the Synergee model shows that load on Central Feeder 13 would be – 472 KW + j4843 KVAR or 4866 KVA at 10% leading power factor (–10% PF). The positive KVAR indicate that Central Feeder 13 is exporting VARs to Project Lost Horizon. This power factor value is not within the RCCS power factor control range but turning the other 1,800 KVAR capacitor bank (C756) on does not have an adverse effect on the area voltages.

For the daytime feeder minimum load, both 1800 KVAR capacitors were off according to the RCCS system and were modeled in Synergee as being off. With Project Lost Horizon operating at 99% power factor importing VARs, the Synergee model shows the load on Central Feeder 13 as – 5422 KW + j5857 KVAR or 7981 KVA at 68% leading power factor (–68%). The positive KVAR indicate that Central Feeder 13 is exporting VARs to Project Lost Horizon. There are no

voltage issues with both RCCS controlled capacitor banks off. This power factor value should not cause the RCCS system to switch the capacitors on, however turning either or both capacitor banks on while Project Lost Horizon is operating will cause unacceptably high voltages.

The alternative to PNM system resources having to support large VAR transfers for the Loss of Lost Horizon Substation would be to have Project Lost Horizon remain out of service until Lost Horizon Substation is back in service and Lost Horizon Feeder 14 can be re-energized in its normal configuration.

9.0 PROTECTION

9.1 Normal Configuration: Service From Lost Horizon Substation Feeder 14

Lost Horizon Substation Feeder 14 is protected by a 1200 amp breaker in metal clad switchgear with three GE, DIAC IAC77 phase overcurrent relays and a DIAC IAC77 ground overcurrent relay. There is also a Basler, BE1 reclosing relay. The switchgear bus and feeder backup protection is three GE, DIAC IAC53 phase relays and a GE, DIAC IAC53 ground relay. The transformer protection is three GE, STD differential relays. The XXX Project PV system is connected to the system approximately 3.02 miles from the substation. Approximately 5.86 miles from the XXX Project PV system, there is a three phase Nova Recloser.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 1732 amps of fault current on the 208V distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 10MW PV system.

Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder.

The XXX Project does not require any system protection improvements to be made to the Lost Horizon Substation feeder 14 under normal configuration.

9.1 Contingency Configuration: Central Feeder 13 Picks Up Lost Horizon Feeder 14

Central Substation feeder 13 is protected by a 1200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclosing relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, CA differential relays. The XXX Project PV system will be approximately 10.06 miles from the substation. Approximately 12.67 miles from the XXX Project PV system, there is a 400amp, 3-shot sectionalizer. There is also a 70 amp three phase hydraulic recloser, a 100 amp three phase hydraulic recloser, and one three phase electronic recloser, 11.81, 7.76 and 5.86 miles away, respectively from the XXX Project PV system.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 1732 amps of fault current on the 208V distribution system as noted on the interconnection application.

The study first looked at the impact to the reclosers. The available fault current at each recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. Next the 400 amp sectionalizer was studied and the available fault current, for faults on the system anywhere on the load side of the sectionalizer is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 10MW PV system. Finally, the feeder

breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder.

The XXX Project does not require any system protection improvements to be made to the Central Substation feeder 13 under contingency configuration.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on the feeder loading were evaluated for operating Project Lost Horizon during daylight hours where daylight hours were defined as 7:00 AM to 7:00 PM every day.

The output of Project Lost Horizon exceeds the 2009 maximum and minimum load on Lost Horizon Feeder 14 during daylight hours. However, no Lost Horizon Feeder 14 equipment overloads were identified for the normal feeder configuration.

For the loss of Lost Horizon Substation with Project Lost Horizon operating at full output, the Project Lost Horizon output exceeds the 2009 minimum and maximum load on the backup feeder, Central Feeder 13, during daylight hours. There is approximately 3,919 ft. of 2/0 ACSR, between poles B17D022 and B17B003, which is overloaded when Project Lost Horizon is running at full output for an outage of Lost Horizon Substation. The normal/emergency rating of 2/0ACSR is 280A/280A. The SynerGee model shows that the current through the 2/0ACSR with Project Lost Horizon running at 99% Power Factor importing VARs is 360A balanced during maximum load conditions and 406A balanced for minimum load conditions. If the PV system was allowed to run at maximum output during a Lost Horizon Substation outage, this line section would need to be upgraded to 397AAC conductor. However, the SynerGee model also shows that with Project Lost Horizon running at 30% output and 99% Power Factor importing VARs, the 2/0ACSR conductor is not overloaded and does not need to be upgraded. If project lost horizon is curtailed during a Lost Horizon Substation outage, there are no overload issues.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and

current transformers will be installed for redundancy. The metering equipment will be capable of capturing the PV system's generation profile data in the time intervals specified in the interconnection agreement. Also located at the same point will be communication equipment that will allow PNM to access and download data from the meters into the PNM monitoring system in real time. The meter information will be used to monitor the PV system's output level (KW and KWH) and operational status instantaneously, historically, and for billing purposes.

Communications Cost Estimate:

ONE-TIME Equipment Cost	$XXXX
One-Time Labor Cost	$XXXX
MONTHLY Recurring O&M	$XXXX

Breakdown of the ONE-TIME Equipment Cost:

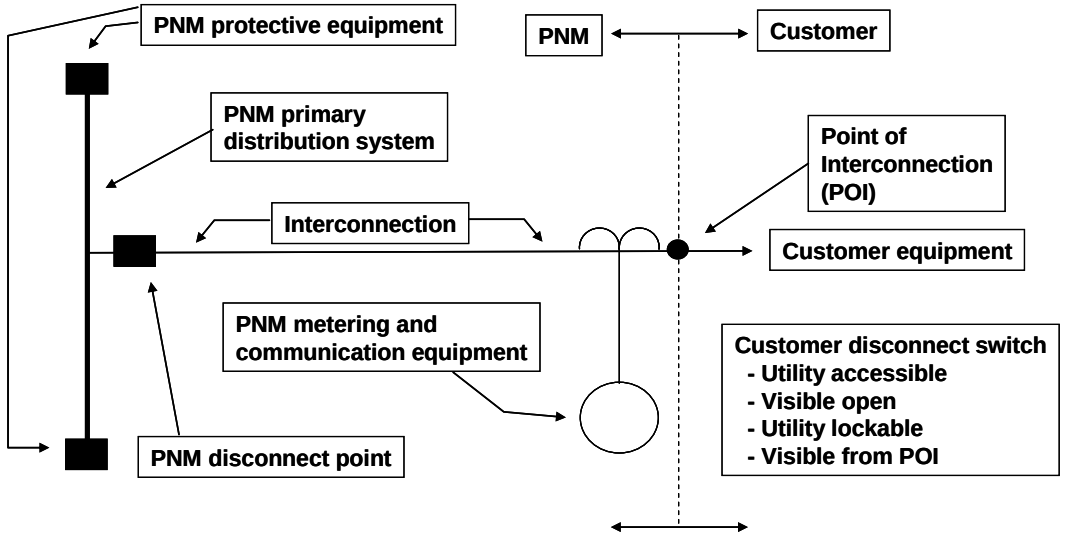
Satellite or TELCO PRIMARY Installation	$XXXX
Microwave or other backup Install	$XXXX
Channel Bank Equipment	$XXXX

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 4 is a one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 4 – Typical Project Interconnection

Typical connection of a Photovoltaic system to the PNM distribution system



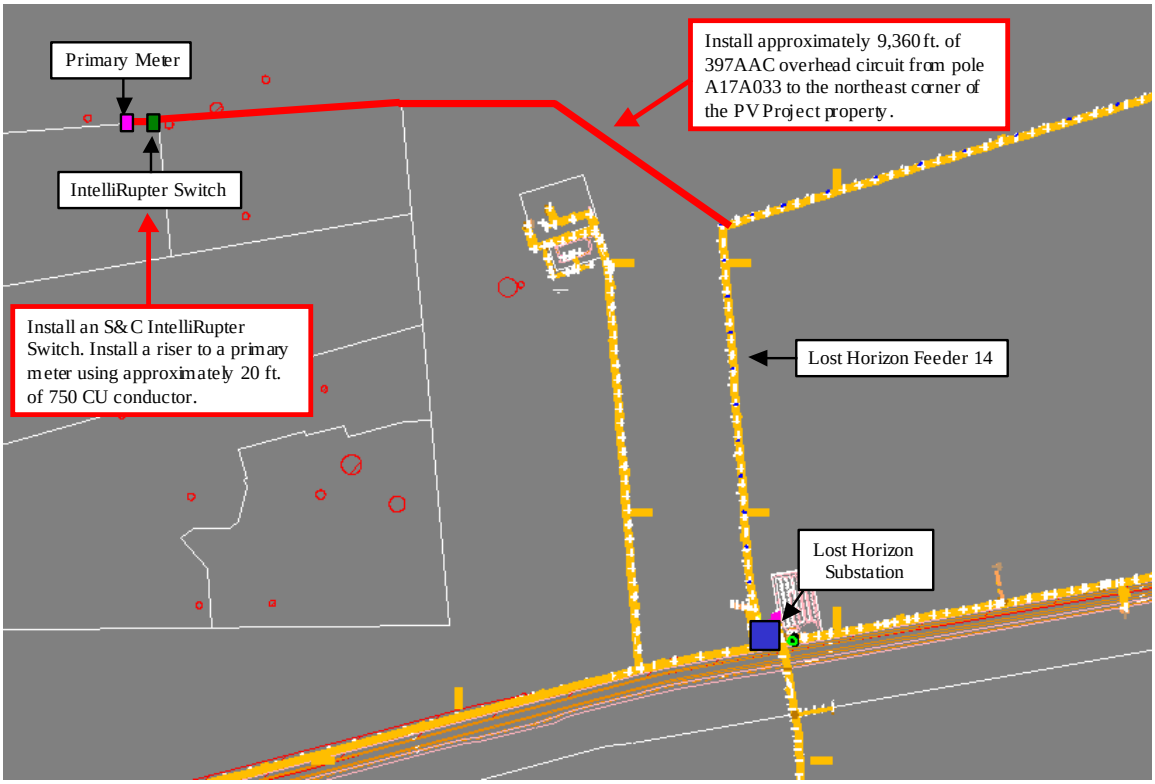
The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project Lost Horizon to the PNM distribution system, a line extension is required. No other system upgrades are required as long as Project Lost Horizon is only allowed to operate at 30% of it's rated output at 99% power factor importing VARs during a loss of Lost Horizon Substation, or is not allowed to operate during the loss of the substation. The interconnection consists of:

- Building approximately 9,360 ft. of new 397 AAC overhead circuit from pole A17A033 to the northeast corner of the PV site property. (See Figure 5).
- Install one S&C IntelliRupter switch (See Figure 5).
- Install Primary Metering (See Figure 5).

Figure 5 – Line Extension for Interconnection



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 15.

Table 15 - Project Lost Horizon Interconnection Cost

	ESTIMATED COSTS 2010$
PNM disconnect point	$XXXXX
Interconnection*	$XXXXX
PNM metering	$XXXXX
Communications	$XXXXX
TOTAL	**$XXXXX**

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition is not expected to be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA). The NOA will also require the facility to operate at 99% power factor importing VARs as a condition to maintain interconnection to the EPS.

16.0 LOST HORIZON SUBSTATION OUTAGES

Since Distribution Planning recommends that during an outage of Lost Horizon Substation, Project Lost Horizon will be completely curtailed until Lost Horizon Substation can be placed back into service, a historical review of the outage history for Lost Horizon Substation was completed. Table 16 shows that the likelihood and duration of an outage of Lost Horizon Feeder 14 is minimal.

Table 16. – Five Year History of Outages that Affected Lost Horizon Feeder 14

OUTAGE_BEGAN	OUTAGE_RESTORE	OUTAGE TIME (HH:MM)	CAUSE_TEXT	WEATHER_OM	OPERATOR_COMMENT
10/7/06 9:17 AM	10/7/06 10:20 AM	1:03	85 Transmission Line 115 kV	1 Normal	BW 115kV transmission line tripped to lockout due to a paraglider in the lines. Transmission crew opened up BW61A to isolate and power operations closed transmission breaker to restore power.
3/1/07 2:08 PM	3/1/07 2:55 PM	0:47	29 Cutout Failure	1 Normal	Crew found two broken cutout fuses at riser pole. Crew refused with 2-65t fuses to restore power.
6/6/07 2:21 PM	6/6/07 10:10 PM	7:49	85 Transmission Line 115 kV	2 High wind	Transmission pole broken by high winds, this tripped the LO high line out,Los Horizon substation was on this high line. Crew made repairs to transmission structure and replaced LOHO14 riser arrestors to restore power.
9/1/07 4:15 PM	9/1/07 5:30 PM	1:15	32 Lightning	3 Lightning	Lost Horizons 12 tripped and closed once, then circuit switcher opened. SW 3046 was closed for third restore. See TMS 183381, 183374 and 183375.
9/13/07 10:19 AM	9/13/07 12:48 PM	2:29	11 Bird ph 220-1056	1 Normal	Blown overhead single-phase lateral cutout fuse due to unidentifiable bird. Crew refused cutout with 100T fuse to restore power. Has been bird guarded.
8/21/08 8:23 AM	8/21/08 9:35 AM	1:12	32 Lightning	3 Lightning	Three phase riser fuse blown due to lightning. Crew refused with a 100T fuse to restore power.
7/22/10 8:22 AM	7/22/10 9:30 AM	1:08	11 Bird ph 220-1056	1 Normal	Two blown overhead cutout fuses at three-phase riser going to primary meter 33139 due to a starling. Crew refused cutout with two 100T fuses to restore power.

17.0 CONCLUSIONS

The location of Project Lost Horizon results in an interconnection with Lost Horizon Feeder 14. Project Lost Horizon has an adverse impact on the PNM distribution system when operating at 100% power factor. Voltage control must be maintained by operating at a fixed 99% power factor importing VARs. During an outage of Lost Horizon Substation, Distribution Planning recommends that the facilities be completely curtailed until Lost Horizon Substation can be placed back into service. When operating as stated above, analysis shows voltages will remain within the PNM criteria of ANSI C84.1. The automatic control of voltage by the substation LTC may cause the LTC to operate, but this is not anticipated to have an adverse effect. There are no anticipated issues with operating Project Lost Horizon in conjunction with PNM's RCCS System. The Project output will cause a flow of electricity from the distribution system through the substation transformer but the difference is minimally greater than 5 MW, therefore no transmission voltage issues are anticipated. Analysis also showed that operating Project Lost Horizon 10 MW at full output for a loss of Lost Horizon Substation does cause some 2/0 ACSR

conductor to exceed its rating. However, since Distribution Planning recommends that Project Lost Horizon remain out of service during a loss of Lost Horizon Substation, the 2/0 ACSR conductor rating is not exceeded. Finally, analysis shows that the variation in output of Project Lost Horizon is not anticipated to cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Lost Horizon and has determined that there are no adverse impacts associated with a 10,000 KVA AC source operated at a fixed 99% power factor importing VARs that is connected to Lost Horizon Substation via Lost Horizon Feeder 14 as long as Project Lost Horizon remains off during a loss of Lost Horizon Substation.

Distribution Planning has determined that no system upgrades are required to ensure that electric service to all customers on Lost Horizon Substation is maintained within established PNM voltage, equipment and fault protection criteria as long as Project Lost Horizon remains off during a loss of Lost Horizon Substation. An alternative to requiring that Project Lost Horizon remain out of service for a loss of Lost Horizon Substation would be for PNM to install a new 115 - 12.47kV transformer at Lost Horizon Substation and extend a dedicated circuit to Project Lost Horizon Substation. This option was not evaluated in this study due to the anticipated high cost of the option.

XXX

Project Tome
4,000 KVA PV Generation Project

Small Generator Interconnection
System Impact Study

(SGI-PNM-2010-04)

April 2011

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution
Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for XXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

The XXX submitted a 'Small Generator Interconnection Request' for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 4,000 KVA AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as "Project Tome" and would be connected to Tome Feeder 12. An application was submitted based on the 'Open Access Transmission Tariff of Public Service Company of New Mexico', 'Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW'. The Interconnection System Impact Study (Study) was performed by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts (Distribution Planning).

The estimated cost of connecting Project Tome to the distribution primary is:

	ESTIMATED COSTS 2011$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRuptor)	$ 52,000	~ 16 week lead time ~ 3 days to build
Overhead line extension	$ 44,500	~ 16 week lead time ~ 1 weeks to build
Primary metering	$ 25,000	~ 3 week lead time ~ 4 days to build
Environmental	$ 2,889	
Right of Way	$ 13,500	
Communication	$ 45,000	
Communication monthly O&M	$ 3,500	
TOTAL	**$ 182,889** **Plus monthly O&M of $3,500**	**5-6 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

The application notes that the Satcon Powergate Plus PVS 500 inverter will be used for the Project. This inverter is UL 1741 compliant.

This Study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the PNM distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Distribution Planning performed a screening analysis of the Project Tome 4 MVA PV system operating at 100% (unity) power factor and determined there an adverse impact on the PNM electric distribution system during contingency configurations. There are two options to mitigate the adverse impact. Option 1 is to operate during all electric system conditions, normal and contingent, at a fixed 99% power factor with the Project injecting 3,960 KW into the electric distribution system and absorbing 564 KVAR from the electric distribution system at the POI. Option 2 is establishment of an operating procedure to address the adverse impact.

Distribution Planning recommends that an operating procedure be developed and implemented to address identified adverse voltage impacts.

The Project location will result in an interconnection with Tome Feeder 12 and analysis results were:

1. Establish an operating procedure to address identified adverse voltage impacts to ensure that distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to clouds were found to not cause voltage flicker problems.
4. Project output does not cause conductor ratings to be exceeded.
5. Remotely controlled capacitor bank on the feeder may potentially be de-energized but this does not adversely impact voltages.

6. The Project contribution to fault current does not require the Tome Feeder 12, Tome Substation, First Street Feeder 11, First Street Feeder 12, Manzano Feeder 13 or Manzano Substation, protection scheme be modified.
7. Project output may cause a flow of electricity from the distribution system through the Tome or Manzano substation transformer. There is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Tome and has determined that there are no adverse impacts associated with a 4,000 KVA source operating at 100% (unity) power factor during normal conditions. Project Tome operating at a 100% (unity) power factor has an adverse impact on the PNM electric distribution system during contingent conditions. Voltage control utilizing a different power setting can mitigate this adverse impact. Establishment of an operating procedure is required to address this adverse impact.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Tome Substation is maintained within established PNM voltage, equipment and fault protection criteria. Distribution Planning recommends that an operating procedure be developed and implemented to address identified adverse voltage impacts.

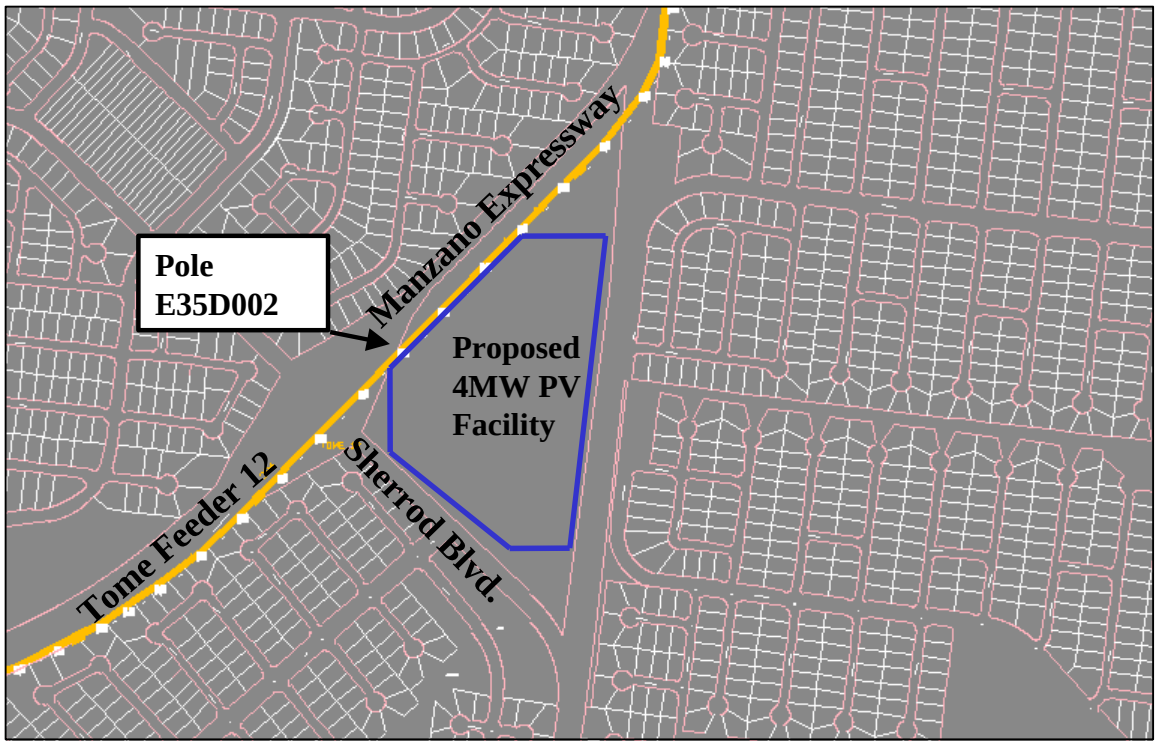
1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts PV electric generation source connected to the PNM distribution primary system identified as Project Tome. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage and current produced by the PV equipment to AC voltage and current. Electric system impacts considered were voltage, equipment ratings, and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Tome proposes to connect a 4,000 KVA AC PV facility to Tome Substation Feeder 12 in Valencia County, NM. The Project will be located on the corner of Manzano Expressway and Sherrod Blvd in Valencia County as shown in Figure 1. The circuit distance from Tome Substation to Project Tome point of interconnection (POI) is about 17,267 ft or 3.27 miles.

***Figure 1* – Project Tome Location**



3.0 SYSTEM CONFIGURATION

Project Tome is connected to Tome Substation Feeder 12. The project will be normally served from Tome Feeder 12 with contingency back up provided by Manzano Feeder 13. Table 1 shows the rating of Tome and Manzano Substations as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Tome	12.6	12.6	14.0	115-12.47
Manzano	14.0	15.5	16.8	115-12.47

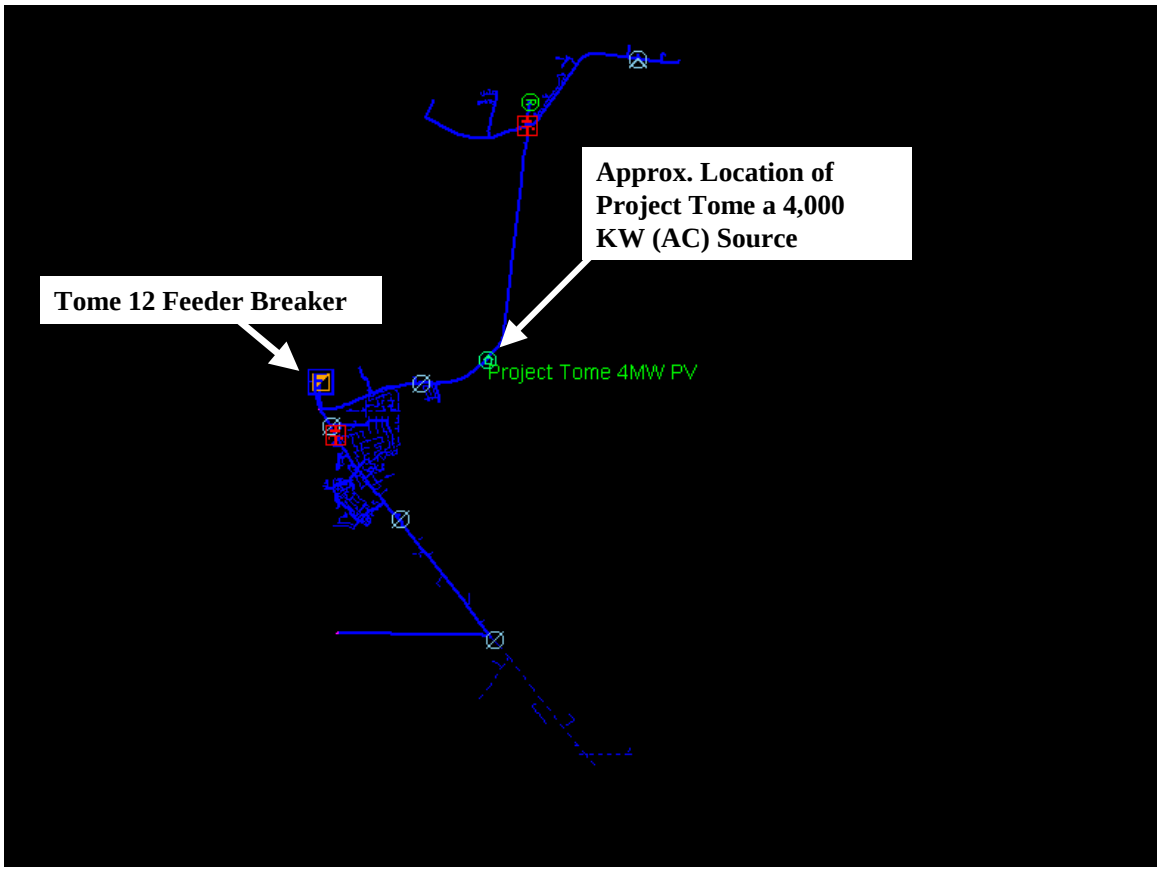
Table 2 shows the non-coincident 2009 peak summer loads for Tome and Manzano Substation and feeders.

***Table 2* – Summer 2009 (June-August) Non-coincident Peak Loads**

Feeder	Summer 2009 Non-coincident Peak Load					% Power Factor
	Date	Time	KW	KVAR	KVA	
Tome						
Tome 11	08/04/09	4:00 PM	802	-253	841	-95.4
Tome 12	08/04/09	5:00 PM	5,192	443	5,211	99.6
Tome 13	07/19/09	4:30 PM	2,817	-538	2,868	-98.2
Tome Sub	08/04/09	5:45 PM	8,579	-401	8,588	-99.9
Manzano						
Manzano 11	07/19/09	4:45 PM	3,229	285	3,242	99.6
Manzano 12	07/19/09	5:45 PM	570	243	619	92.0
Manzano 13	07/13/09	5:30 PM	5,688	960	5,768	98.6
Manzano Sub	07/20/09	1:00 PM	9,180	1,477	9,298	98.7

Figure 2 is a picture of the distribution feeder used in the Advantica Synergee modeling program.

***Figure 2* – Synergee model of Tome Feeder 12**



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours – the first condition is the peak load on each study area distribution circuit and the second condition is the minimum load on each study area distribution circuit. The times for maximum and minimum load are non-coincident for the distribution circuits.

The daylight hours are based on sunrise and sunset time for January through December in the Albuquerque area using 2009 data.

Table 3 shows the daylight hours time (mountain time zone) range for each month for determining the maximum and minimum loading used in a PV system impact study.

***Table 3* – Time range for PV studies**

Time Range for PV Studies		
7 AM - 7 PM	**8 AM – 5 PM**	**8 AM – 4 PM**
April	March	January
May	September	February
June	October	November
July		December
August		

The maximum and minimum daylight hours loading on the Tome Feeders 12 and Manzano Feeder 13 are shown in Table 4:

***Table 4* – Max/min Daylight Hours Load**

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Tome 12								
August 4, 2009	5 PM	5,192	443	5,211	99.6	219	272	226
May 23, 2009	7 AM	1,572	-518	1,655	-95.0	84	72	70
Manzano 13								
July 13, 2009	5 PM	5,688	1,002	5,776	98.5	271	279	238
May 24, 2009	7 AM	1,636	-1,658	2,329	-70.2	106	108	103

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Table 5 lists the capacitors on the four feeders and their status at the minimum and maximum load times.

***Table 5* – Status of capacitors**

Capacitor	KVAR Size	Fixed or Switched	Status		
			Min load	Max load	Non - Coincident
Tome 12					
C107V	600	F	ON	ON	ON
C151V	1,200	S	OFF	ON	ON
Manzano 13					
C113V	1,200	S	ON	ON	ON
C1230V*	1,200	S	OFF	OFF	OFF
C150V	600	F	ON	ON	ON

* This capacitor was installed after the 2009 peak. For this study it will be assumed to be ON for initial peak conditions.

4.1 Screen for PV system impacts associated with power factor setting

Scenarios reviewed by this Study define an inverter based distributed generation facility operating with a power factor other than unity to be a facility that is absorbing or importing reactive power from the distribution system at the POI. Inverter control systems can be adjusted to allow the PV system to absorb reactive power (Vars) from the distribution system at the POI. Recommendations to absorb reactive power at the POI to mitigate voltage rise impact on the electric distribution system will be evaluated for all operating conditions when reviewing the impact of the Project maintaining voltages within ANSI C84.1 criteria limits.

The electric distribution system was screened to determine if there are any adverse impacts associated with Project Tome injecting energy into the distribution system at the POI. Project Tome was evaluated operating at a 100% (unity) power factor to determine if system criteria limits were violated. The system was evaluated with and without Project Tome for maximum and minimum load during normal and contingency conditions to ensure the distribution system operated within the voltage criteria limits of ANSI C84.1. Operating conditions resulting in

voltages outside of the criteria limits will require voltage control utilizing a different power factor setting on the PV project.

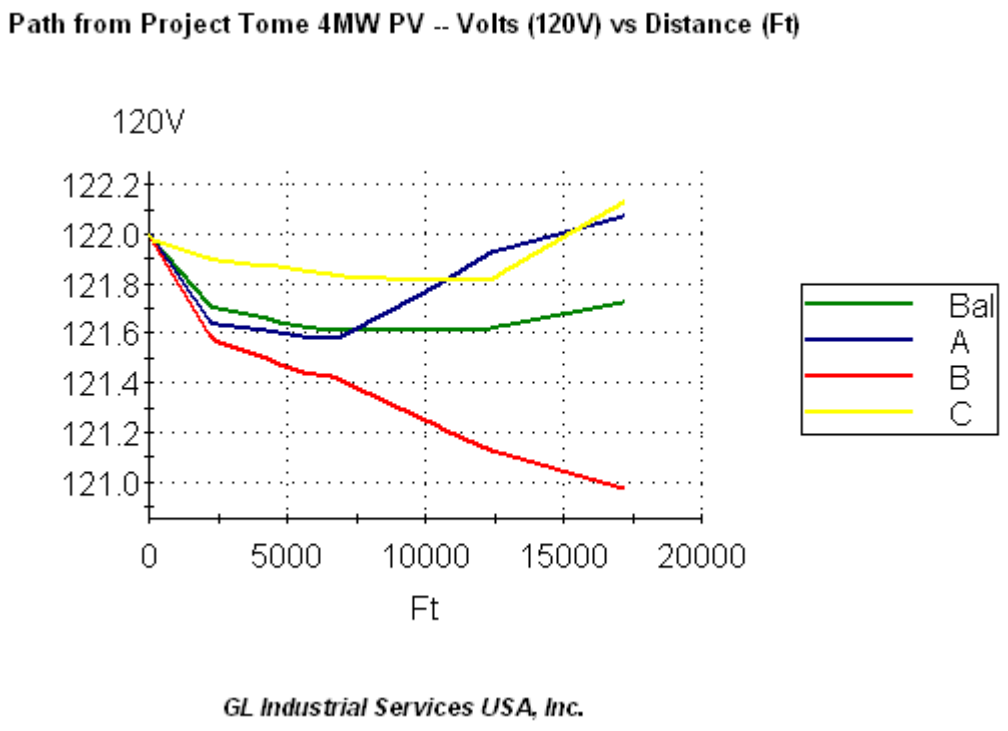
4.2 Voltage impacts on the transmission system

Project Tome operating at a 100% power factor will be injecting 4,000 KW into the distribution system at the POI. The peak load on Tome Substation (see Table 2) is greater than the Project rated output. The minimum load on the Tome Substation does not typically fall below 4 MW so transmission related issues are not anticipated to be associated with Project Tome at maximum or minimum output.

4.3 Voltage impacts for maximum daylight hours load

The Tome Feeder 12 voltage for the feeder daylight hours maximum load for 2009 with and without Project Tome, per the Synergee model, are shown in graphs 1, 2, and 3.

***Graph 1* – Tome Feeder 12 voltage drop from Tome Substation to Project Tome POI for daylight hours maximum load on August 4, 2009. Project Tome is OFF.**

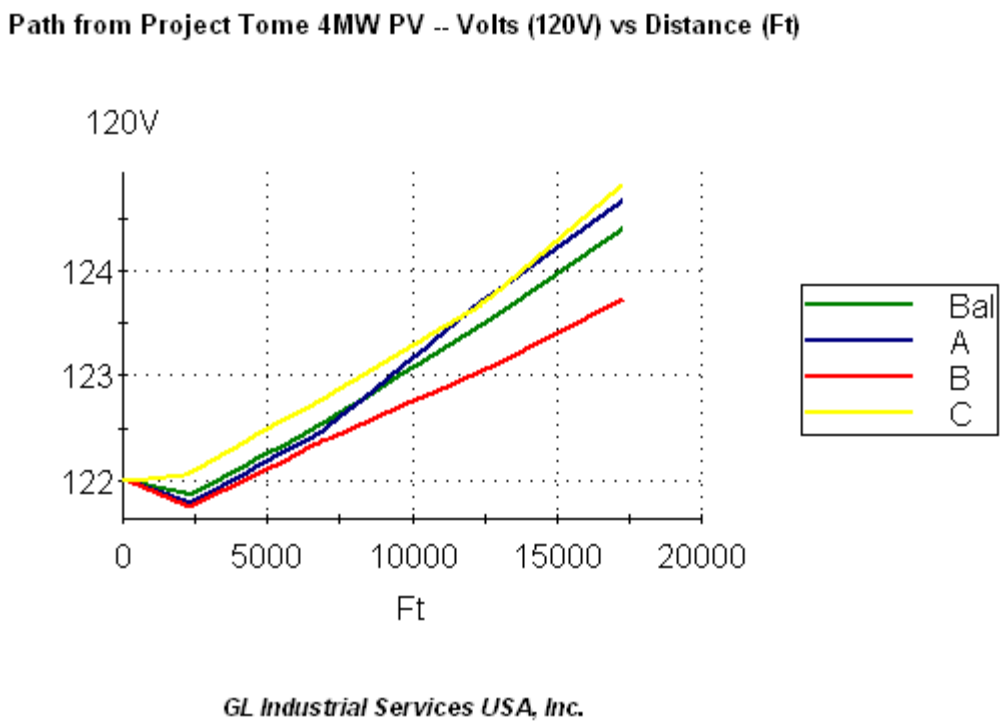


The model voltages at the point of interconnection are:

Phase A – 122.1 volts Phase B – 121.0 volts Phase C – 122.1 volts Balanced – 121.7 volts

The voltages on Tome Feeder 12 prior to the installation of Project Tome are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,200 KVAR switched capacitor being energized.

***Graph 2* – Tome Feeder 12 voltage drop from Tome Substation to Project Tome POI for daylight hours maximum load on August 4, 2009. Project Tome is ON at a 100% power factor.**

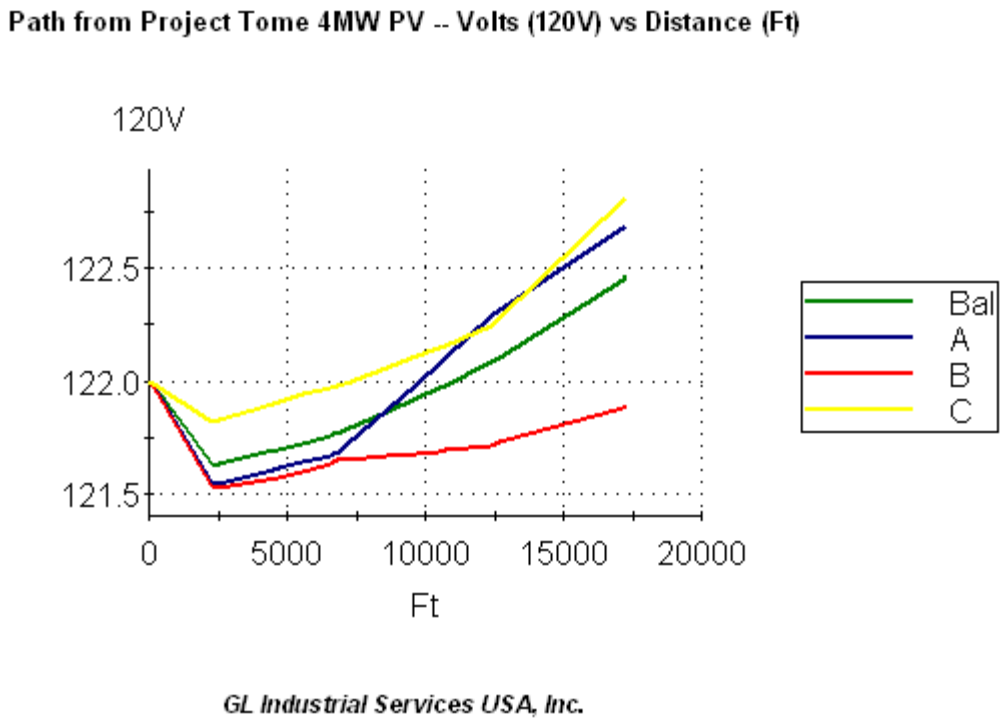


The model voltages at the point of interconnection are:

Phase A – 124.7 volts Phase B – 123.7 volts Phase C – 124.8 volts Balanced – 124.4 volts

The voltages on Tome Feeder 12 after the installation of Project Tome operating at a 100% power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,200 KVAR switched capacitor being energized. However, there are sections of the feeder that are not within the PNM voltage criteria (ANSI C84.1) that are located downstream of Project Tome. By turning off the 1,200 KVAR switched capacitor, the voltages on Tome Feeder 12 are again within the PNM voltage criteria.

<u>Graph 3</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome POI for daylight hours maximum load on August 4, 2009. Project Tome is ON at a 100% power factor. The 1,200 KVAR switched capacitor bank has been turned off.



The model voltages at the point of interconnection are:

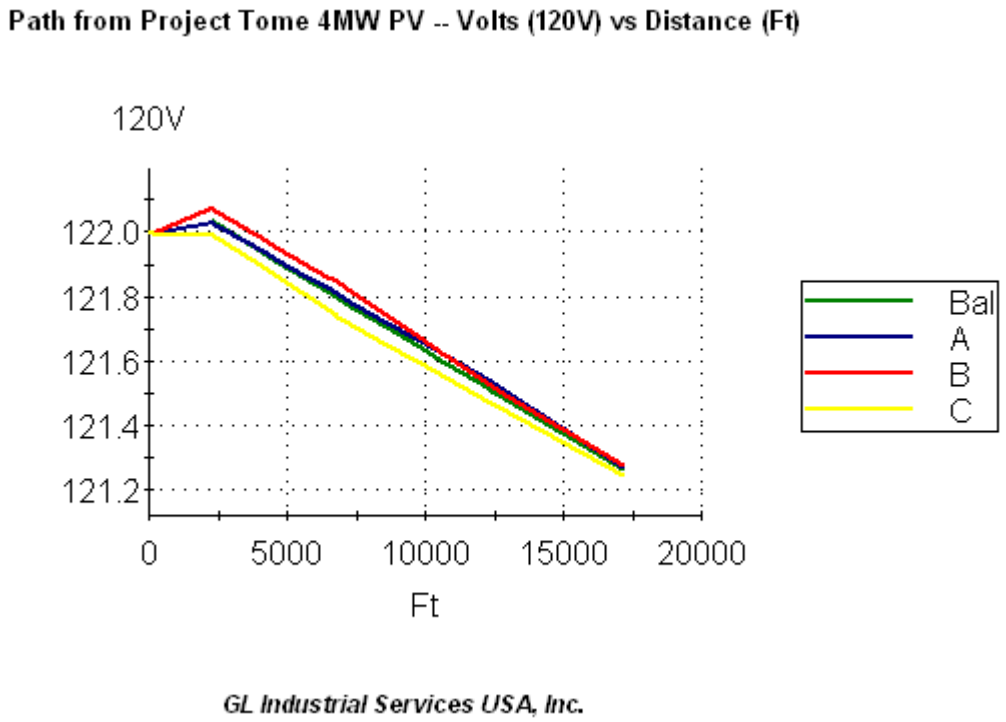
Phase A – 122.7 volts Phase B – 121.9 volts Phase C – 122.8 volts Balanced – 122.5 volts

The voltages on Tome Feeder 12 after the installation of Project Tome operating at a 100% power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,200 KVAR switched capacitor being de-energized.

4.4 Voltage impacts for minimum daylight hours load

The Tome Feeder 12 voltage for the feeder daylight hours minimum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 4 and 5.

<u>Graph 4</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome POI for daylight hours minimum load on May 23, 2009. Project Tome is OFF

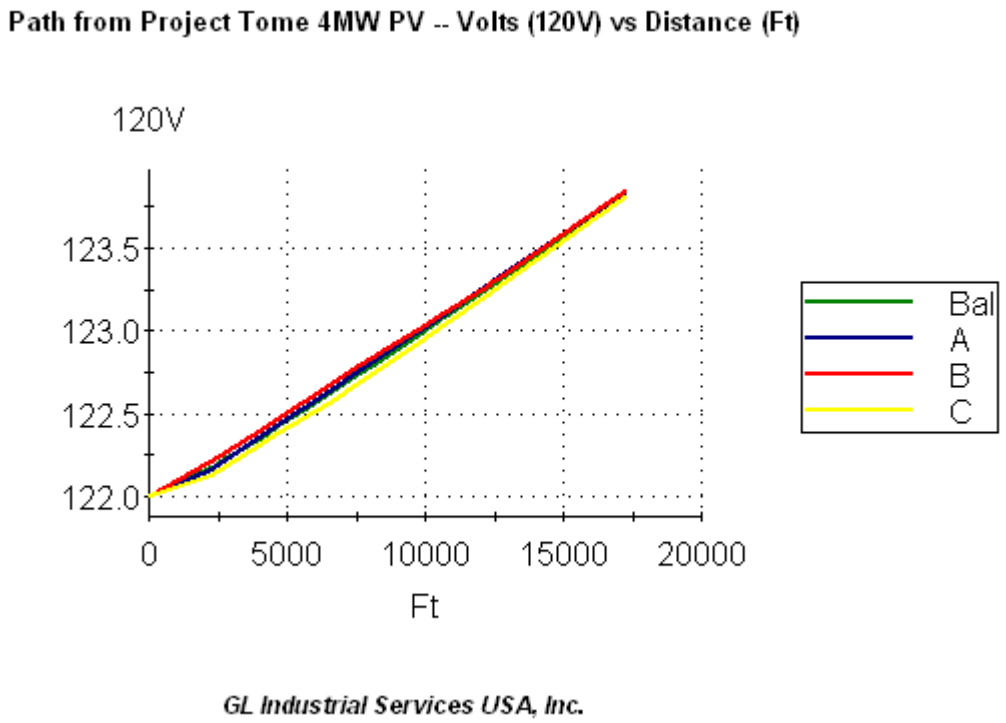


The model voltages at the point of interconnection are:

Phase A – 121.3 volts Phase B – 121.3 volts Phase C – 121.2 volts Balanced – 121.3 volts

The voltages on Tome Feeder 12 prior to the installation of Project Tome are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,200 KVAR switched capacitor being de-energized.

<u>Graph 5</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome POI for daylight hours minimum load on May 23, 2009. Project Tome is ON at a 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.8 volts Phase B – 123.8 volts Phase C – 123.8 volts Balanced – 123.8 volts

The voltages on Tome Feeder 12 after the installation of Project Tome operating at a 100% power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,200 KVAR switched capacitor being de-energized.

In conclusion, Project Tome operating at a 100% power factor output does cause the voltage on Tome Feeder 12 at the Project POI to increase but the voltage stays within the PNM criteria of ANSI C84.1.

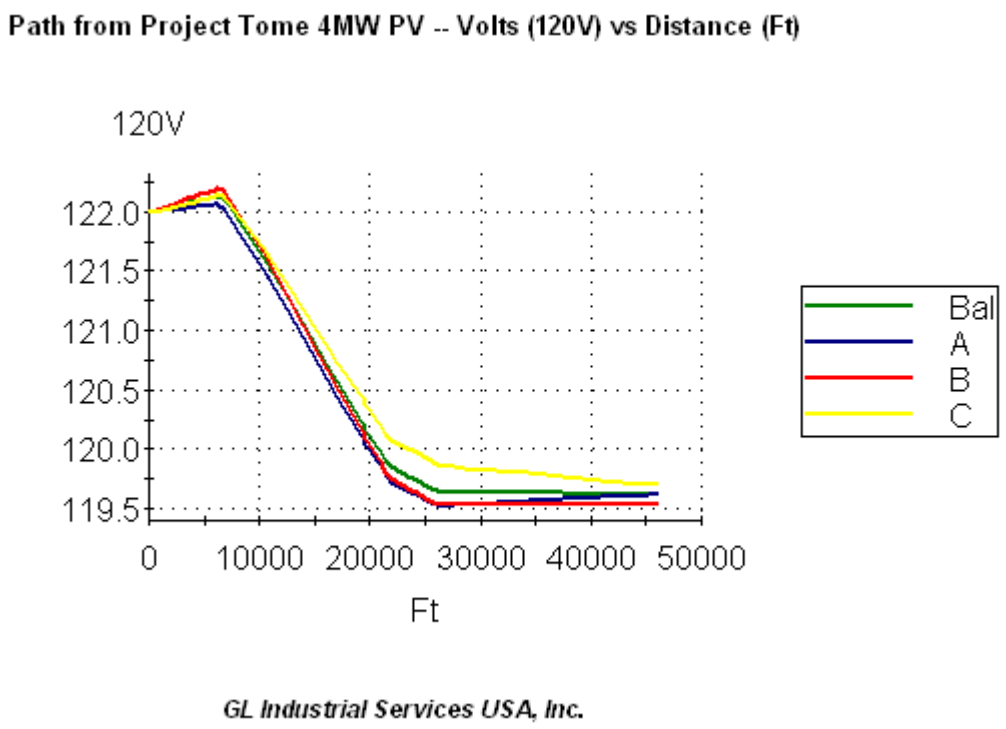
4.5 Voltage impacts during an outage of Tome Substation

Manzano Feeder 13 backs up Tome Feeder 12 when Tome Substation is out-of-service due to maintenance or equipment failure. The minimum and maximum loading on Manzano Feeder 13 and Tome Feeder 12 for the hours of 7AM to 7PM is shown in Table 4. For the condition of Tome Substation out-of-service, 34% of Tome Feeder 12 gets transferred to Manzano Feeder 13.

4.5.1 Voltage impacts for daylight hours minimum load during an outage of Tome Substation

The Manzano Feeder 13 voltage for daylight hours minimum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 6, 7, and 8.

***Graph 6* – Manzano Feeder 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours minimum load on May 23,2009. Project Tome is OFF.**

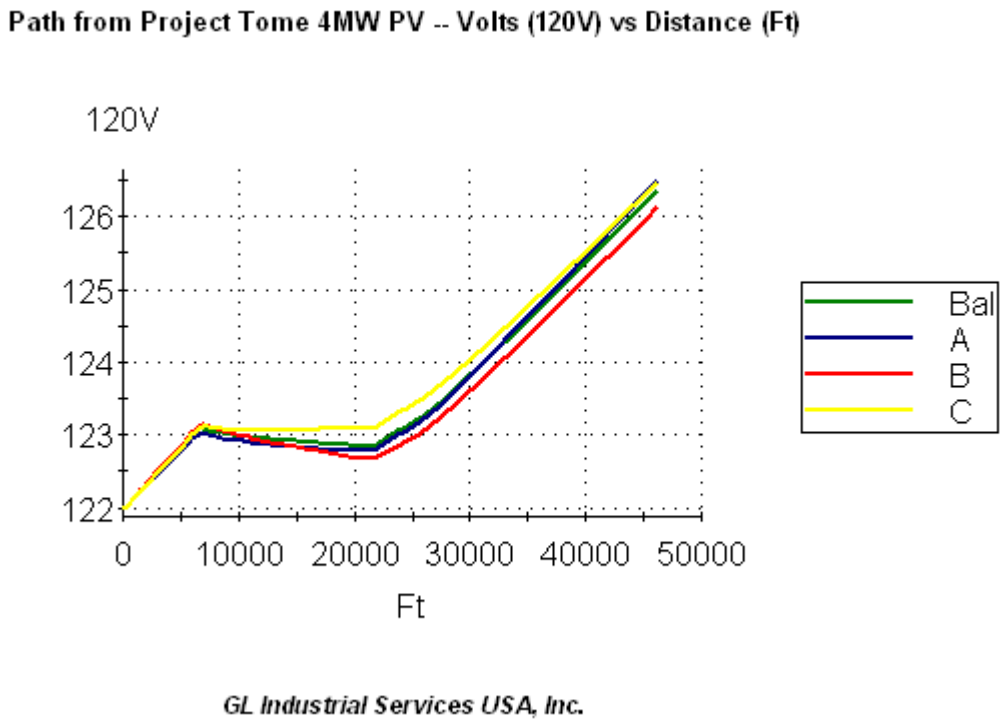


The model voltages at the point of interconnection are:

Phase A – 119.6 volts Phase B – 119.5 volts Phase C – 119.7 volts Balanced – 119.6 volts

The voltages on Manzano Feeder 13 prior to the installation of Project Tome are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on two of the three 1,200 KVAR switched capacitors being de-energized.

***Graph 7* – Manzano Feeder 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours minimum load on May 23, 2009. Project Tome is ON at a 100% power factor.**



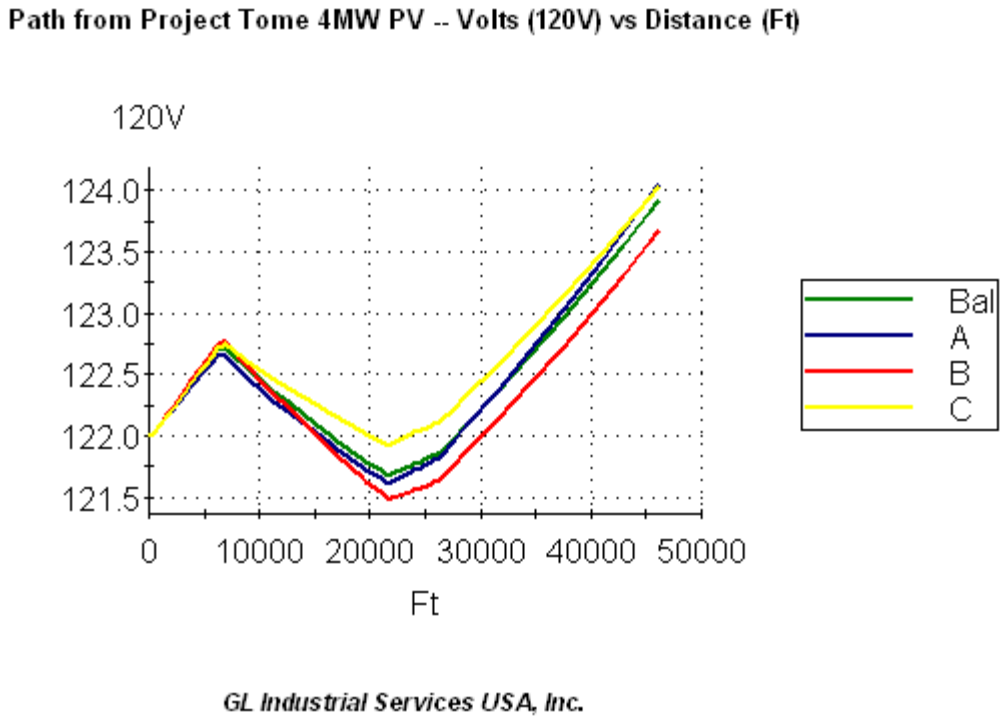
The model voltages at the point of interconnection are:
Phase A – 126.5 volts Phase B – 126.1 volts Phase C – 126.5 volts Balanced – 126.4 volts

The voltages on Manzano Feeder 13 after the installation of Project Tome operating at a 100% power factor are above the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are unacceptable. This model is based on two of the three 1,200 KVAR switched capacitor banks being de-energized.

Project Tome has an adverse impact on the PNM electric distribution system for an outage of Tome Substation with 34% of Tome Feeder 12 transferred to Manzano Feeder 13 when operating at a 100% (unity) power factor. Voltage control utilizing a different power factor setting on the Project is recommended.

Setting Project Tome to a 99% power factor such that the Project is injecting 3,960 KW into the distribution system at the POI and absorbing 564 KVAR from the distribution system at the POI to mitigate voltages above the ANSI C84.1 criteria limits. Graph 8 is the same condition as shown in Graph 7 except Project Tome is modeled with a 99% power factor.

***Graph 8* – Manzano Feeder 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours minimum load on May 23, 2009. Project Tome is ON at a 99% power factor.**



The model voltages at the point of interconnection are:
Phase A – 124.1 volts Phase B – 123.7 volts Phase C – 124.0 volts Balanced – 123.9 volts

The voltages on Manzano Feeder 13 after the installation of Project Tome operating at a 99% power factor are below the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are acceptable. This model is based on two of the three 1,200 KVAR switched capacitor banks on Tome Feeder 12 being de-energized.

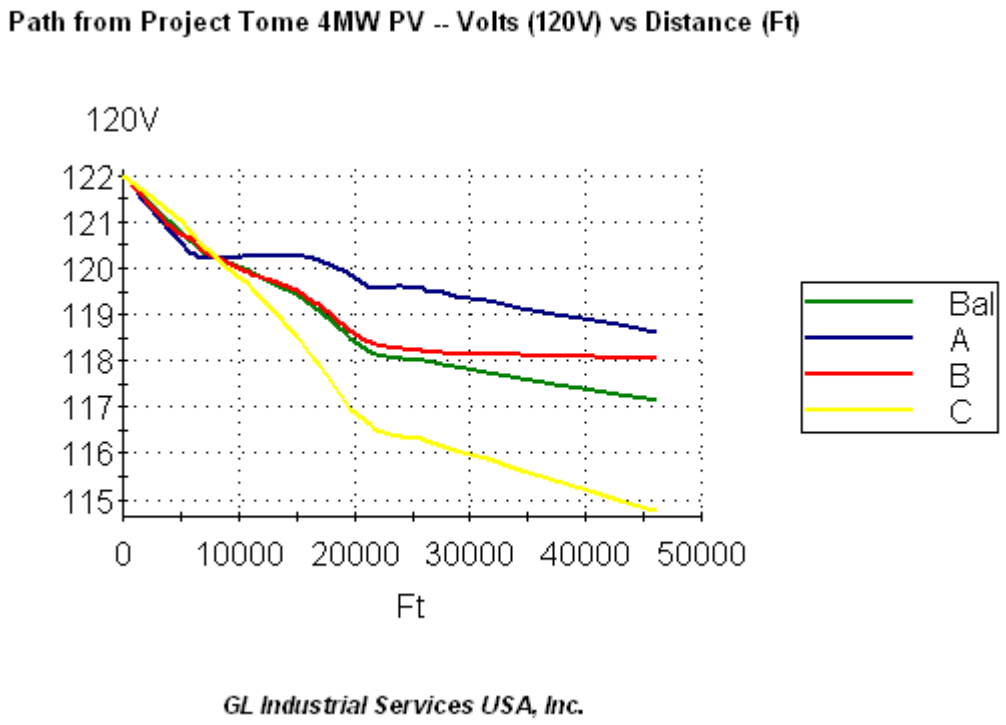
In conclusion, Project Tome operating at a 100% (unity) power factor has an adverse impact on the PNM electric distribution system when Manzano Feeder 13 is supporting Tome Feeder 12

due to Tome Substation being out-of-service. Voltages at the Project POI are above the ANSI C84.1 upper limit and are unacceptable. Voltage control utilizing a different power factor setting on the Project is necessary. Setting Project Tome to a 99% power factor such that the Project is injecting 3,960 KW into the distribution system at the POI and absorbing 564 KVAR from the distribution system at the POI is required to mitigate voltage above the ANSI C84.1 criteria limits. Project Tome operating at a 99% power factor output does cause the voltage on Manzano Feeder 13 when supporting Tome Feeder 12 due to Tome Substation being out-of-service to increase but the voltage stays within the PNM criteria of ANSI C84.1.

4.5.2 Voltage impacts for daylight hours maximum load during an outage of Tome Substation

The Manzano Feeder 13 voltage for the feeder maximum daylight hours load for July 13, 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 9, 10, and 11.

***Graph 9* - Manzano Feeder 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours maximum load on August 4, 2009. Project Tome is OFF.**

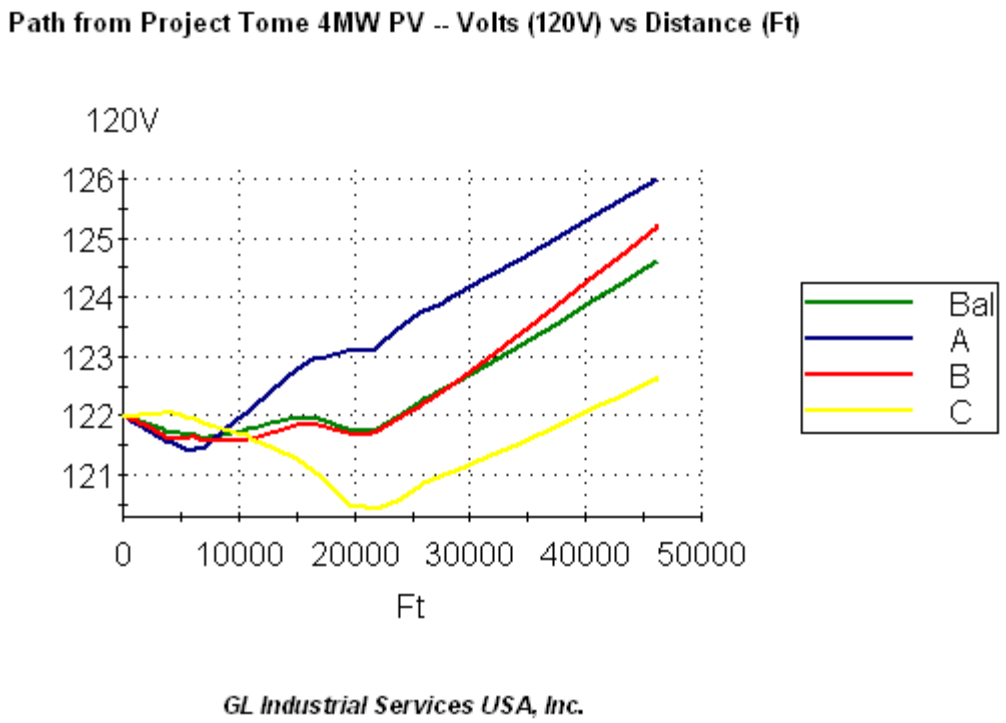


The model voltages at the point of interconnection are:

Phase A – 118.6 volts Phase B – 118.1 volts Phase C – 114.7 volts Balanced –117.1 volts

The voltages on Manzano Feeder 13 for the loss of Tome Substation contingency prior to the installation of Project Tome are within the PNM voltage criteria ANSI C84.1 Range A service voltage at the POI and are marginally acceptable. This model is based on all three of the 1200 KVAR switched capacitor banks being energized.

***Graph 10* - Manzano 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours maximum load on August 4, 2009. Project Tome is ON at a 100% power factor.**



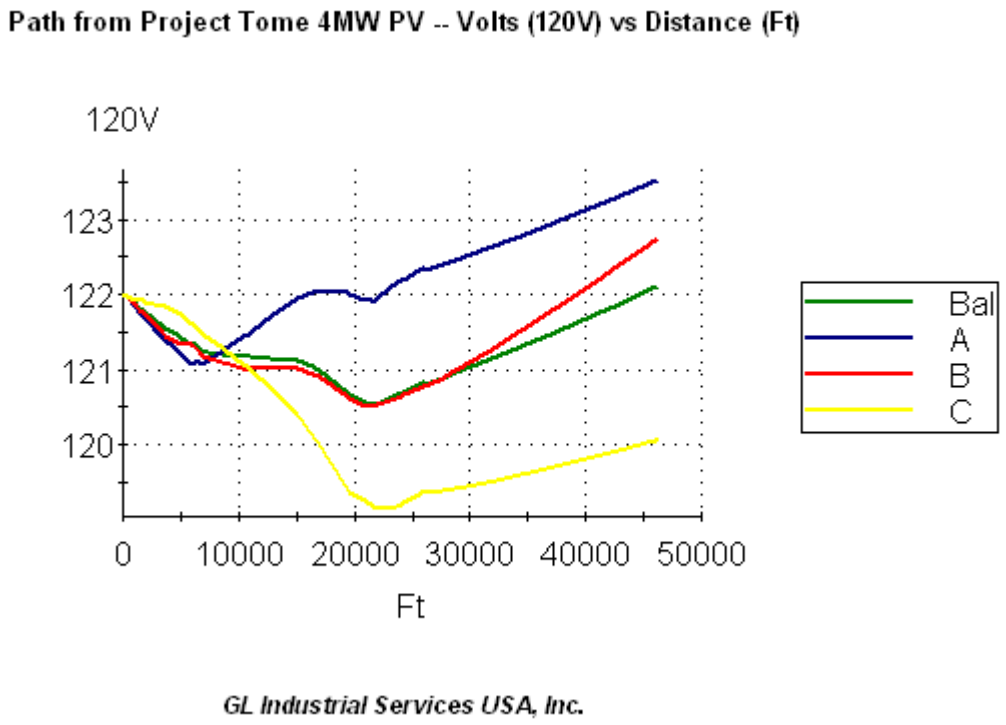
The model voltages at the point of interconnection are:
Phase A – 126.0 volts Phase B – 125.2 volts Phase C – 122.6 volts Balanced – 124.6 volts

The voltages on Manzano Feeder 13 after the installation of Project Tome operating at a 100% power factor are at the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are marginally acceptable. This model is based on two of the three 1,200 KVAR switched capacitor banks being energized.

Project Tome has the potential to have an adverse impact on the PNM electric distribution system for an outage of Tome Substation with 34% of Tome Feeder 12 transferred to Manzano Feeder 13 when operating at a 100% unity power factor. Voltage control utilizing a different power factor setting on the Project is recommended.

Setting Project Tome to a 99% power factor such that the Project is injecting 3,960 KW into the distribution system at the POI and absorbing 564 KVAR from the distribution system at the POI to mitigate the voltages above the ANSI C84.1 criteria limits. Graph 11 is the same condition as shown in Graph 10 except Project Tome is modeled with a 99% power factor.

<u>Graph 11</u> – Manzano Feeder 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours maximum load on August 4, 2009. Project Tome is ON at a 99% power factor.



The model voltages at the point of interconnection are:
Phase A – 123.5 volts Phase B – 122.8 volts Phase C – 120.1 volts Balanced – 122.1 volts

The voltages on Manzano Feeder 13 after the installation of Project Tome operating at a 99% power factor are below the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI

and are acceptable. This model is based on two of the three 1,200 KVAR switched capacitor banks being energized.

In conclusion, Project Tome operating at a 100% (unity) power factor has an adverse impact on the PNM electric distribution system when Manzano Feeder 13 is supporting Tome Feeder 12 due to Tome Substation being out-of-service. Voltages at the Project POI reach the ANSI C84.1 upper limit and are unacceptable. Voltage control utilizing a different power factor setting on the Project is necessary. Setting Project Tome to a 99% power factor such that the Project is injecting 3,960 KW into the distribution system at the POI and absorbing 564 KVAR from the distribution system at the POI is required to mitigate voltages above the ANSI C84.1 criteria limits. Project Tome operating at a 99% power factor output does cause the voltage on Manzano Feeder 13 when supporting Tome Feeder 12 due to Tome Substation to increase but the voltage stays within the PNM criteria of ANSI C84.1.

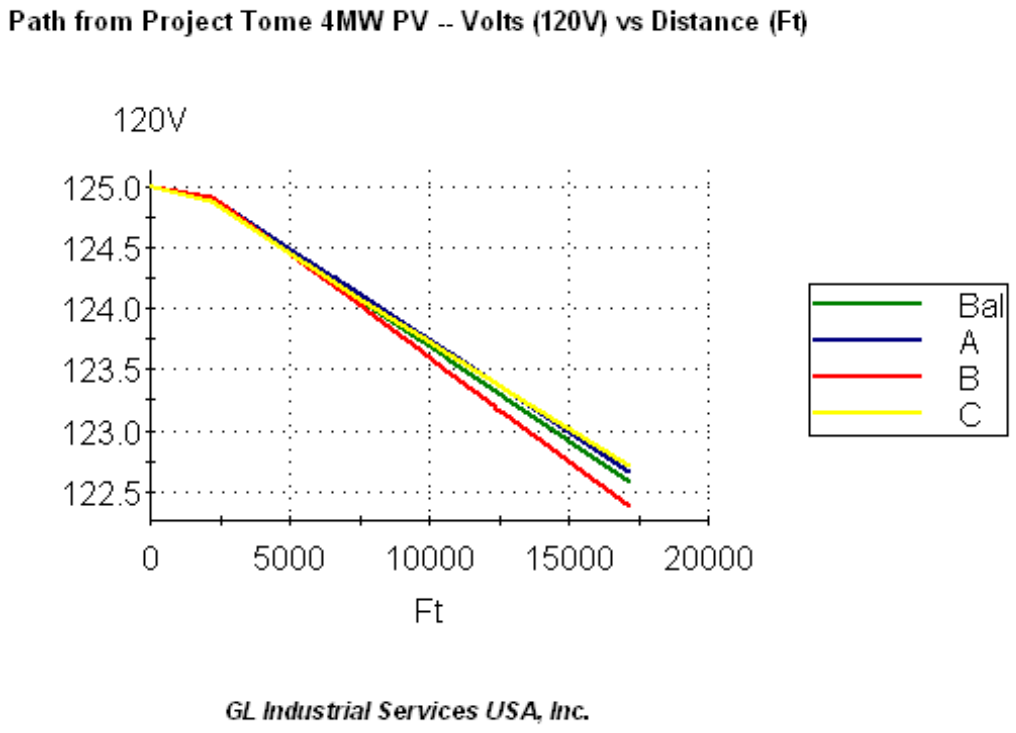
4.6 Voltage impacts during an outage of Manzano Substation

Tome Feeder 12 backs up Manzano Feeder 13 when Manzano Substation is out-of-service due to maintenance or equipment failure. For the condition of Manzano Substation out-of-service, 33% of Manzano Feeder 13 is transferred to Tome Feeder 12. In addition, existing operating procedures recommend that the Tome Substation LTC be set to 125 Volts when Tome Feeder 12 backs up Manzano Feeder 13.

4.6.1 Voltage impacts for daylight hours minimum load during an outage of Manzano Substation

The Tome Feeder 12 voltage for daylight hours minimum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 12, 13 and 14.

<u>Graph 12</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome POI for daylight hours minimum load for a Manzano Substation outage. Project Tome is OFF.

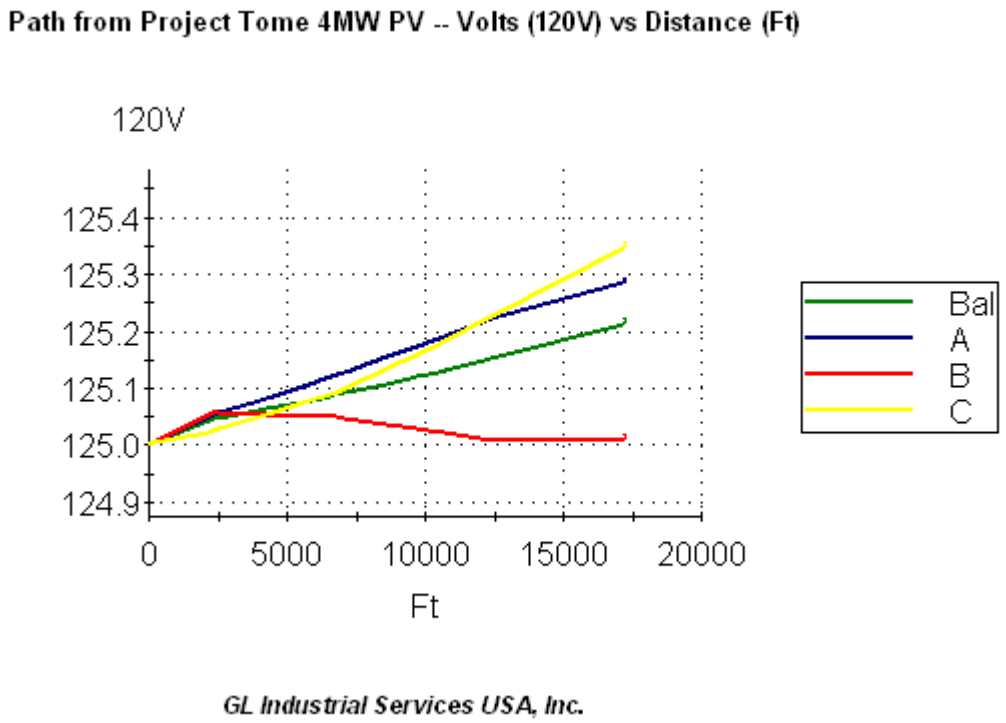


The model voltages at the point of interconnection are:

Phase A – 122.7 volts Phase B – 122.4 volts Phase C – 122.7 volts Balanced – 122.6 volts

The voltages on Tome Feeder 12 from Tome Substation to Project Tome POI during an outage of Manzano Substation prior to the installation of Project Tome stay within the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on the Tome Substation LTC set at 125 volts and the 1,200 KVAR switched capacitor bank being de-energized.

<u>Graph 13</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours minimum load for an outage of Manzano Substation. Project Tome is ON at a 100% power factor. Tome Substation LTC at 125 Volts.



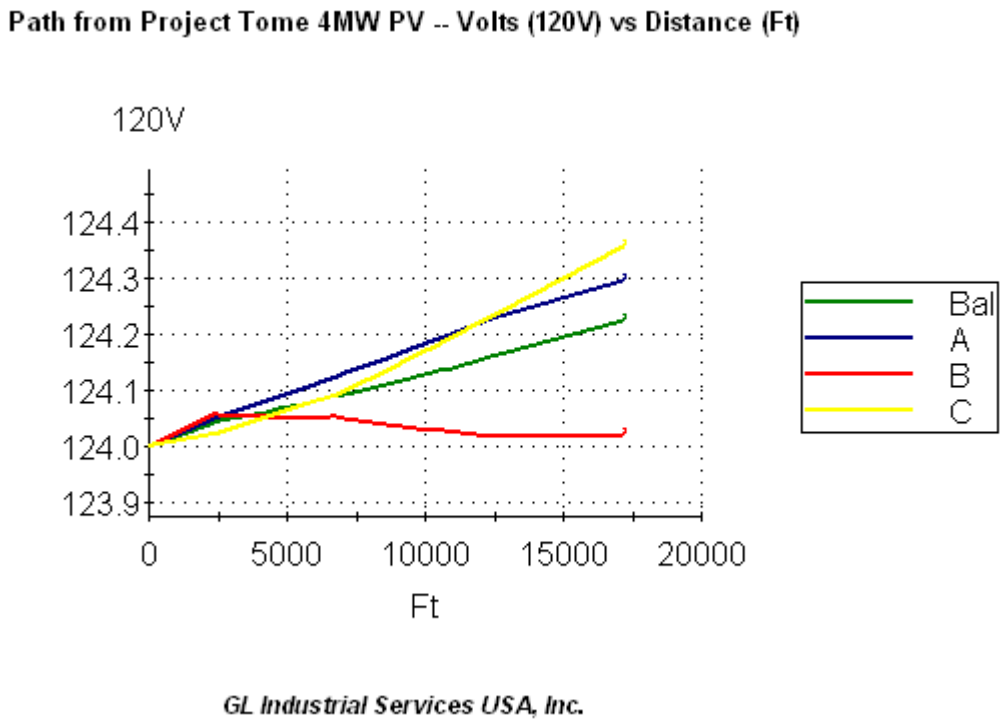
The model voltages at the point of interconnection are:

Phase A – 125.3 volts Phase B – 125 volts Phase C – 125.4 volts Balanced – 125.2 volts

The voltages on Tome Feeder 12 from Tome Substation Project Tome POI during an outage of Manzano Substation after the installation of Project Tome operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) and are marginally acceptable. This model is based on the Tome Substation LTC set at 125 Volts and the 1,200 KVAR switched capacitor bank being de-energized.

Project Tome has the potential to have an adverse impact on the PNM electric distribution system for an outage of Manzano Substation with 33% of Manzano Feeder 13 transferred to Tome Feeder 12 when operating at a 100% unity power factor and the Tome Substation LTC at 125 Volts. The LTC setting should be reduced.

<u>Graph 14</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours minimum load for an outage of Manzano Substation. Project Tome is ON at a 100% power factor. Tome Substation LTC at 124 Volts.



The model voltages at the point of interconnection are:

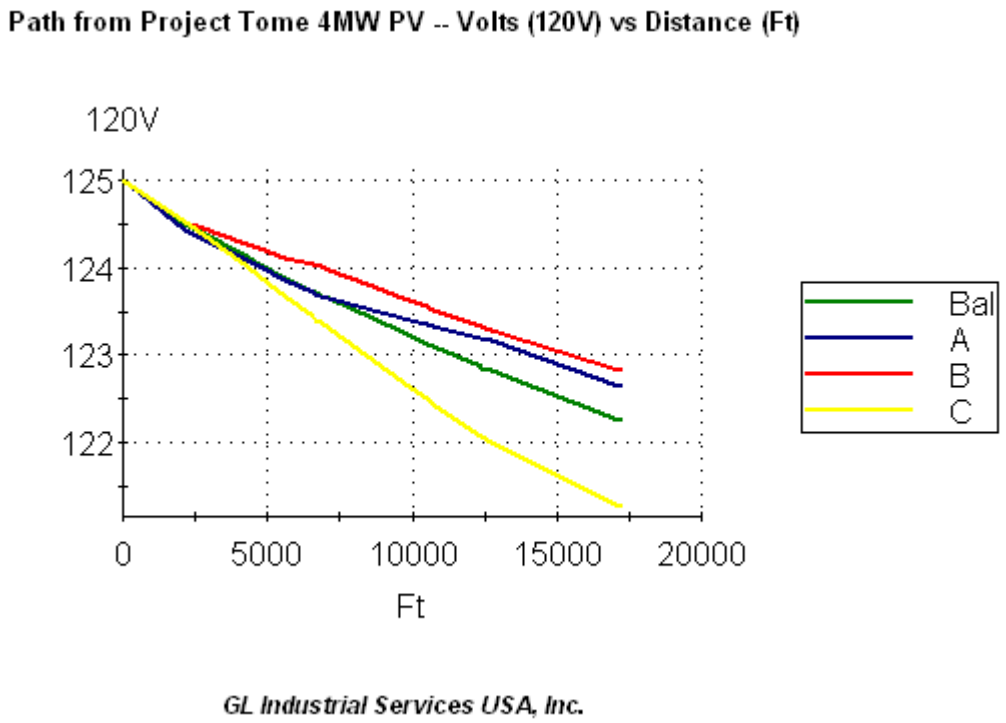
Phase A – 124.3 volts Phase B – 124.0 volts Phase C – 124.4 volts Balanced – 124.2 volts

The voltages on Tome Feeder 12 after the installation of Project Tome operating at a 100% power factor with the Tome Substation LTC set at 124 Volts are below the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are acceptable. This model is based on the 1,200 KVAR switched capacitor bank being de-energized.

4.6.2 Voltage impacts for daylight hours maximum load during an outage of Manzano Substation

The Tome Feeder 12 voltage for daylight hours maximum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 15, 16 and 17.

<u>Graph 15</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours maximum load for an outage of Manzano Substation. Project Tome is OFF.

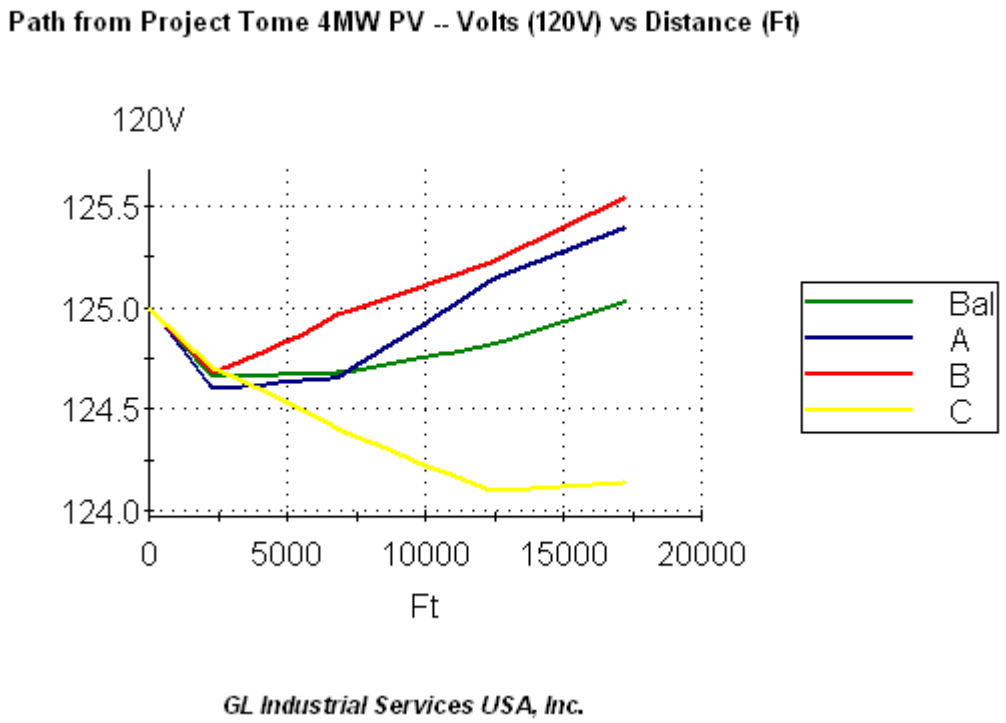


The model voltages at the point of interconnection are:

Phase A – 122.7 volts Phase B – 122.8 volts Phase C – 121.3 volts Balanced – 122.3 volts

The voltages on Tome Feeder 12 from Tome Substation to Project Tome POI during an outage of Manzano Substation prior to the installation of Project Tome are within the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on the Tome Substation LTC set at 125 Volts and the 1,200 KVAR switched capacitor bank being energized.

<u>Graph 16</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours maximum load for an outage of Manzano Substation. Project Tome is ON at 100% power factor. Tome Substation LTC at 125 Volts.



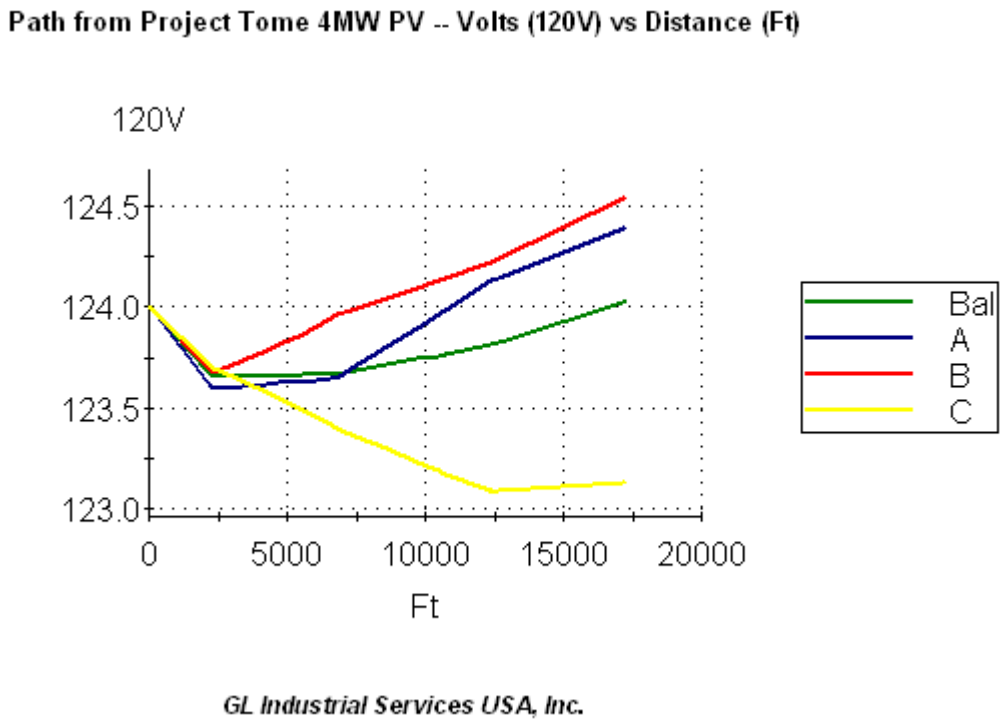
The model voltages at the point of interconnection are:

Phase A – 125.4 volts Phase B – 125.6 volts Phase C – 124.2 volts Balanced – 125.0 volts

The voltages on Tome Feeder 12 from Tome Substation to Project Tome POI during an outage of Manzano Substation after the installation of Project Tome operating at 100% power factor are below the PNM voltage criteria (ANSI C84.1) and are marginally acceptable. This model is based on the Tome Substation LTC set at 125 Volts and the 1,200 KVAR switched capacitor bank being energized.

Project Tome has the potential to have an adverse impact on the PNM electric distribution system for an outage of Manzano Substation with 33% of Manzano Feeder 13 transferred to Tome Feeder 12 when operating at a 100% unity power factor with the Tome Substation LTC set at 125 Volts. The LTC setting should be reduced.

***Graph 17* – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours maximum load for an outage of Manzano Substation. Project Tome is ON at 100% power factor. Tome Substation LTC at 124 Volts.**



The model voltages at the point of interconnection are:

Phase A – 124.4 volts Phase B – 124.6 volts Phase C – 123.1 volts Balanced – 124.0 volts

The voltages on Tome Feeder 12 from Tome Substation to Project Tome POI during an outage of Manzano Substation after the installation of Project Tome operating at 100% power factor with the Tome Substation LTC set at 124 Volts are below the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on the 1,200 KVAR switched capacitor bank being energized.

In conclusion, Project Tome operating at a 100% (unity) power factor has the potential to have an adverse impact on the PNM electric distribution system when Tome Feeder 12 is supporting Manzano Feeder 13 due to Manzano Substation being out-of-service when the Tome Substation LTC is set at 125 Volts. Voltages at the Project POI are near the ANSI C84.1 upper limit and are only marginally acceptable. Reducing the Tome Substation LTC setting to 124 Volts is necessary to mitigate voltages above the ANSI C84.1 criteria limits. Project Tome

operating at a 100% power factor output does cause the voltage on Tome Feeder 12 when supporting Manzano Feeder 13 due to an outage of Manzano Substation to increase but the voltage stays within the PNM criteria of ANSI C84.1 when the Tome Substation LTC setting is 124 Volts.

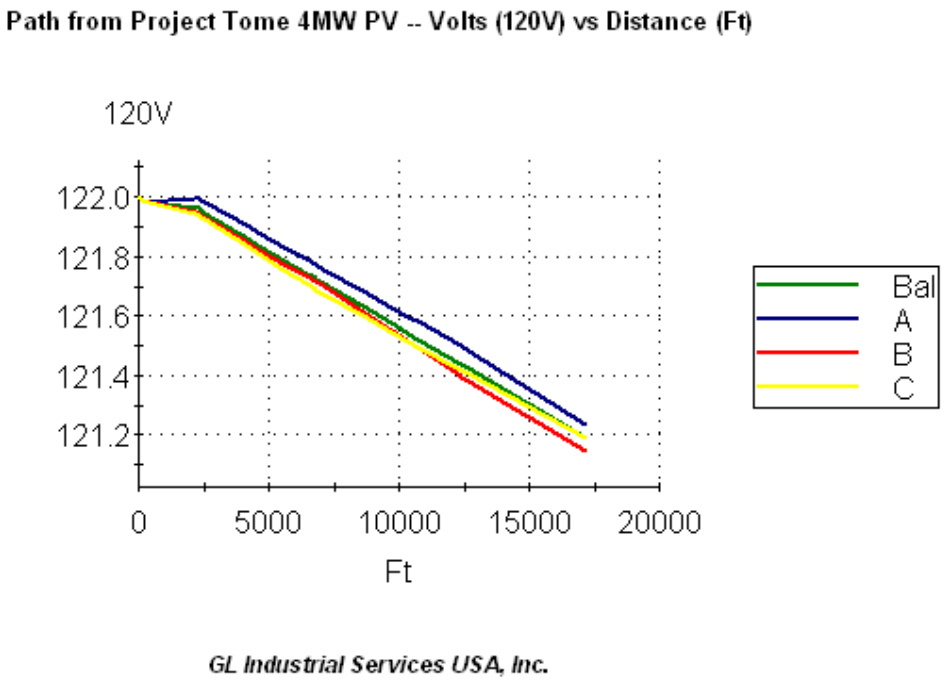
4.7 Voltage impacts during an outage of First Street Substation

Tome Feeder 12 backs up First Street Feeders 11 and 12 when First Street Substation is out-of-service due to maintenance or equipment failure. For the condition of First Street Substation out-of-service, 46% of First Street Feeder 11 and 100% of First Street Feeder 12 is transferred to Tome Feeder 12.

4.7.1 Voltage impacts for daylight hours minimum load during an outage of First Street Substation

The Tome Feeder 12 voltage for daylight hours minimum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 18 and 19.

***Graph 18* – Tome Feeder 12 voltage drop from Tome Substation to Project Tome POI for daylight hours minimum load for a First Street Substation outage. Project Tome is OFF.**

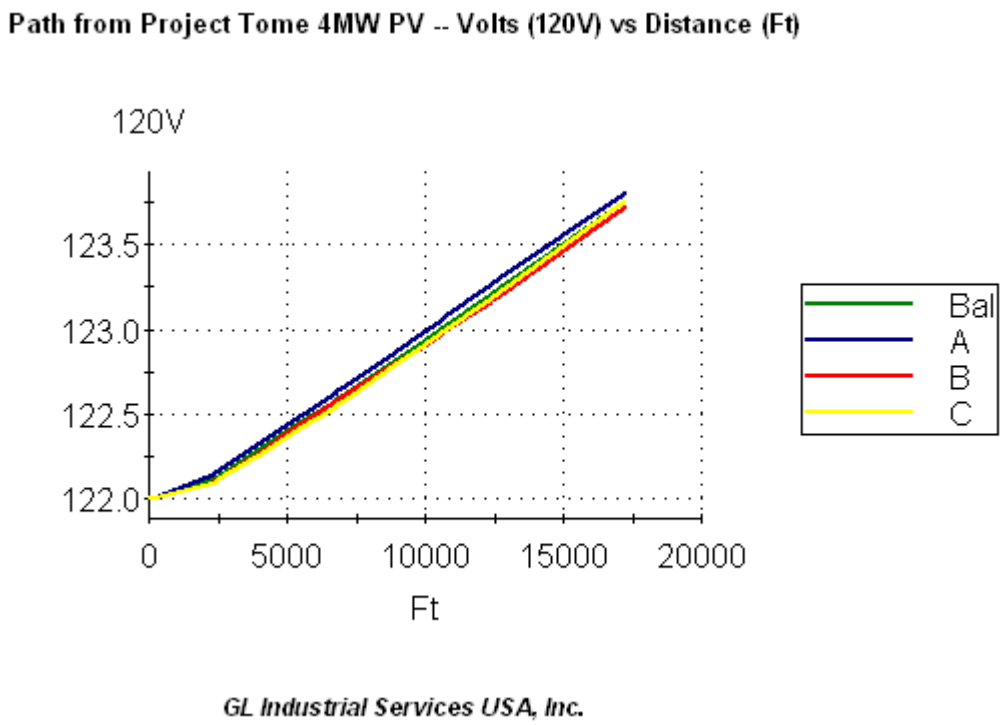


The model voltages at the point of interconnection are:

Phase A – 121.2 volts Phase B – 121.1 volts Phase C – 121.2 volts Balanced – 121.2 volts

The voltages on Tome Feeder 12 from Tome Substation to Project Tome POI during an outage of First Street Substation prior to the installation of Project Tome stay within the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on one of the three 1,200 KVAR switched capacitor banks being de-energized.

***Graph 19* – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours minimum load for an outage of First Street Substation. Project Tome is ON at a 100% power factor.**



The model voltages at the point of interconnection are:

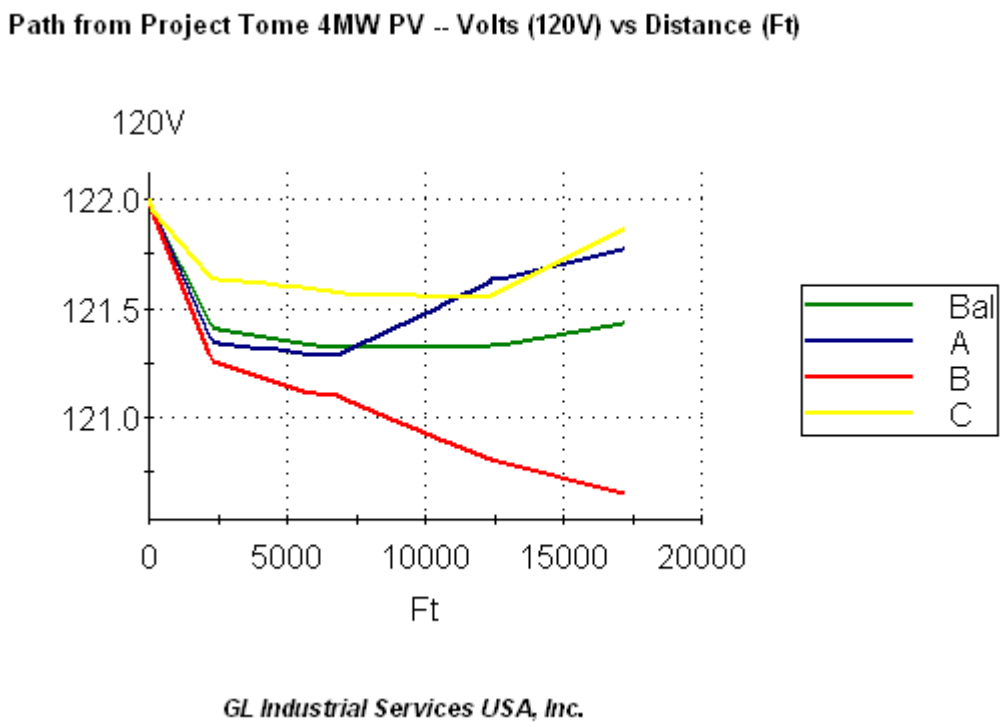
Phase A – 123.8 volts Phase B – 123.7 volts Phase C – 123.8 volts Balanced – 123.8 volts

The voltages on Tome Feeder 12 from Tome Substation Project Tome POI during an outage of First Street Substation after the installation of Project Tome operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on one of three 1,200 KVAR switched capacitor banks being de-energized.

4.7.2 Voltage impacts for daylight hours maximum load during an outage of First Street Substation

The Tome Feeder 12 voltage for daylight hours maximum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 20 and 21.

<u>Graph 20</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours maximum load for an outage of First Street Substation. Project Tome is OFF.

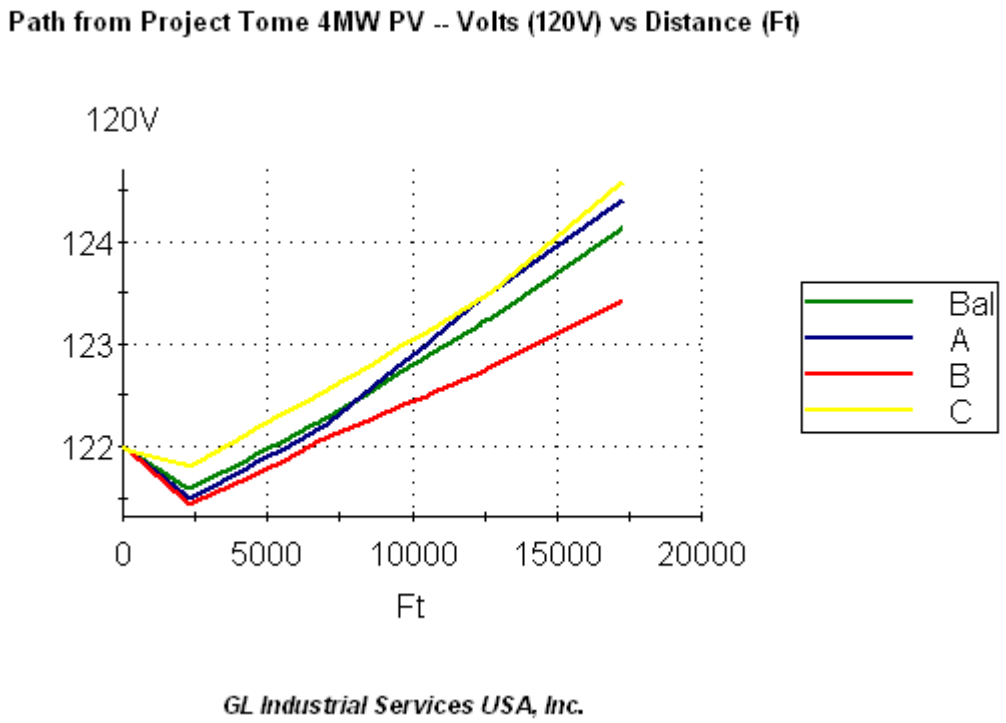


The model voltages at the point of interconnection are:

Phase A – 121.8 volts Phase B – 120.7 volts Phase C – 121.9 volts Balanced – 121.4 volts

The voltages on Tome Feeder 12 from Tome Substation to Project Tome POI during an outage of First Street Substation prior to the installation of Project Tome are within the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on all three of the 1,200 KVAR switched capacitor banks being energized.

<u>Graph 21</u> – Tome Feeder 12 voltage drop from Tome Substation to Project Tome for daylight hours maximum load for an outage of First Street Substation. Project Tome is ON at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 124.4 volts Phase B – 123.4 volts Phase C – 124.6 volts Balanced – 124.1 volts

The voltages on Tome Feeder 12 from Tome Substation to Project Tome POI during an outage of First Street Substation after the installation of Project Tome operating at 100% power factor are below the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on all three of the 1,200 KVAR switched capacitor banks being energized.

In conclusion, Project Tome operating at a 100% (unity) power factor output does cause the voltage to increase on Tome Feeder 12 when supporting First Street Feeders 11 and 12 due to First Street Substation being out-of-service, but the voltage stays within the PNM criteria of ANSI C84.1.

4.8 Voltage impacts overall conclusions

Project Tome will be connected to Tome Feeder 12. The feeder has one 600 KVAR fixed capacitor and one 1,200 KVAR switched capacitor. The switched capacitor is energized for maximum loading and de-energized during minimum loading conditions.

During normal conditions Project Tome maximum output operating at 100% (unity) power factor causes the voltage on Tome Feeder 12 to increase for minimum and maximum load periods when compared to the Project not in-service. The voltages at the POI remain within the acceptable limits of PNM voltage criteria ANSI C84.1.

Tome Feeder 12 is supported by Manzano Substation Feeder 13 for an outage of Tome Substation. Operating at 100% (unity) power factor during minimum load periods the voltage at the POI is above the ANSI C84.1 upper limit of 126 volts, which is unacceptable and during maximum load periods the voltage at the POI is close to the ANSI C84.1 upper limit, which is marginally acceptable.

Tome Feeder 12 is the backup feeder for Manzano Feeder 13 for an outage of Manzano Substation. Operating at 100% (unity) power factor during minimum and maximum load periods the voltage at the POI is close to the ANSI C84.1 upper limit, which is marginally acceptable. This is due to an existing operating procedure that recommends that the Tome Substation LTC be set to 125 Volts when Tome Feeder 12 backs up Manzano Feeder 13. Reducing the setting to 124 Volts mitigates the voltage problem and the voltages at the POI remain within the acceptable limits of PNM voltage criteria ANSI C84.1.

Tome Feeder 12 is the backup feeder for First Street Feeder 11 and First Street Feeder 12 for an outage of First Street Substation. Operating at 100% (unity) power factor during minimum load periods the voltage increases at the POI but remains within the ANSI C84.1 voltage criteria.

There are two options for mitigating Project Tome adverse impacts on the PNM distribution primary system:

OPTION 1

Operate Project Tome with a fixed 99% power factor during all system conditions, normal and contingent. Therefore, the Project, at maximum capability, will inject 3,960 KW into the distribution system at the POI and will absorb 564 KVAR from the distribution system at the POI. This will allow the Project to operate during all electric system conditions.

OPTION 2

Establish an operating procedure based on limiting the voltage on the PNM distribution system at the POI. The procedure must identify the maximum acceptable voltage at the POI and how it will be monitored. If the voltage exceeds acceptable limits the Project will need to adjust its power factor within a reasonable timeframe or PNM will disconnect the Project to prevent adverse voltages. The Project will be reconnected either when the power factor has been adjusted or system conditions allow.

Distribution Planning recommends Option 2 – develop and implement an operating procedure. The adverse impact occurs during a planned or unplanned outage of Tome Substation. The operating procedure must have a process to address and correct adverse voltages whenever they occur, whether during normal and contingent electric system conditions. Additionally, the operating procedure will need to include steps for scheduled maintenance which should have ample time to make adjustments to Project Tome power factor such that it can continue operating and stay connected to the PNM distribution system during the maintenance period.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Tome is served by Tome Feeder 12, and does not have a voltage regulator installed on the feeder. The substation LTC is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 120.5 volts and will reduce the voltage if the substation bus is above 123.5 volts.

Synergee modeling showed that the voltage variance at the substation due to Project Tome operating at a 99% power factor injecting 3,960 KW into the distribution feeder at the POI and absorbing 564 KVAR from the distribution feeder at the POI would be about 0.1 volts for high or low load periods. This voltage variance may cause the substation LTC to operate for high or low load on the feeder but this is not an adverse impact.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Tome POI is shown in Section 4.0. Table 6 summarizes the balanced voltage and the calculated voltage flicker. Table 7 is based on the GE flicker graph.

Table 6 ***- Voltage flicker on Tome Feeder 12 due to Project Tome***

	POI Voltage Tome Feeder 12 Loading	
	Minimum	**Maximum**
Without Project	121.3	121.7
With Project	123.8	122.5
% Voltage Flicker	**2.06**	**0.66**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 7 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
2.06	2/hour	1/minute
0.66	1/min	3/sec

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 6 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 7. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Tome POI to the substation were reviewed using the Synergee feeder model with and without Project Tome operating at a 99% power factor with the project injecting 3,960 KW into the distribution system and absorbing, 564 KVAR from the distribution system.

There were no conductor loading problems from the POI to the substation on Tome Feeder 12 for the normal and contingent system configurations or on Manzano Feeder 13 for the contingent system configuration with and without Project Tome during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. However, Project Tome, for the condition of when Manzano Substation is out-of-service due to maintenance or equipment failure, is recommended to operate at a 99% power factor and will be injecting 3,960 KW into the distribution system and absorbing 564 KVAR from the distribution system. When the inverter is operating, the power factor of the distribution feeder will be affected.

RCCS adjusts the power factor of individual feeders by energizing or de-energizing switched capacitors. Tome Feeder 12 has one 1200 KVAR RCCS capacitor bank and one 600 KVAR fixed capacitor bank. The Summer 2009 peak load on the feeder was 5,192 KW + j 443 KVAR or 5,211 KVA at a 99.6% lagging power factor (See Table 2) with the 1,200 RCCS capacitor bank energized. Project Tome at 100% power factor at the POI would change the apparent feeder loading to 1,192 KW + j 443 KVAR or 1, 271 KVA at a 93.8% lagging power factor.

The new power factor on Tome Feeder 12 exceeds the RCCS power factor control point, but all capacitors are energized prior to this condition, therefore any issues addressed would be driven by pre-existing conditions. The remotely controlled capacitor banks on the feeder may potentially be de-energized, but this does not adversely impact voltages.

9.0 PROTECTION

9.1 Normal Configuration – Service from Tome Feeder 12

Tome Substation feeder 12 is protected by a 1200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, HU differential relays. The Tome 4MW Project PV system will be connected to the system approximately 3.26 miles from the substation.

Fault analysis of the system for Tome 12 was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 223 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the four reclosers on the feeder. The available fault current at all reclosers, for faults on the system anywhere on the loadside of the reclosers is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 4 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Tome 4MW does not require any system protection improvements to be made to the Tome Substation feeder 12.

9.2 Normal Feeder as Backup Feeder - Tome Feeder 12 picks up 33% of Manzano 13

Fault analysis of the system when Tome 12 is a backup feeder for was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 223 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the five reclosers on the feeder. The available fault current at all reclosers, for faults on the system anywhere on the loadside of the reclosers is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 4 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Tome 4MW does not require any system protection improvements to be made to the Tome Substation feeder 12 as a backup feeder for Manzano 13.

9.3 Normal Feeder as Backup Feeder - Tome Feeder 12 Picks up 46% of First Street Feeder 11 and 100% of First Street Feeder 12

Fault analysis of the system when Tome 12 is a backup feeder for was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 223 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the six reclosers on the feeder. The available fault current at all reclosers, for faults on the system anywhere on the loadside of the reclosers is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination

with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 4 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Tome 4MW does not require any system protection improvements to be made to the Tome Substation feeder 12 as a backup feeder for First Street 11 and 12.

9.4 Contingency Configuration – Manzano Feeder 13 picks up 34% Tome Feeder 12

Manzano Substation feeder 13 is protected by a 1200 amp breaker in metal clad switchgear with a GE, MDP extremely inverse phase overcurrent relay and a very inverse ground overcurrent relay. There is also an ABB, MMCO extremely inverse phase overcurrent relays and a very inverse ground overcurrent relay. There is also a GE, SLR reclosing relay. The switchgear bus and feeder backup protection is an ABB, MMCO very inverse phase relay and an ABB, MMCO very inverse ground relay. There is also a GE, MDP very inverse phase relay. The transformer protection is three GE, STD differential relays. The Tome 4 MW Project PV system will be connected to the system approximately 8.75 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 223 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the four reclosers on the feeder. The available fault current at all reclosers, for faults on the system anywhere on the loadside of the reclosers is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 4 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Tome 4MW does not require any system protection improvements to be made to the Manzano Substation feeder 13.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Tome output exceeds the 2009 minimum load on Tome Feeder 12 during daylight hours. No Tome Feeder 12 overloads were identified.

Project Tome output exceeds the 2009 minimum load on Manzano Feeder 13 during daylight hours. No Manzano Feeder 13 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. The metering equipment will be capable of capturing the PV system's generation profile data in the time intervals specified in the interconnection agreement. Also located at the same point will be communication equipment that will allow PNM to access and download data from the meters into the PNM monitoring system in real time. The meter information will be used to monitor the PV system's output level (KW and KWH) and operational status instantaneously, historically, and for billing purposes.

Communications Cost Estimate:

ONE-TIME Equipment Cost	$35,000
One-Time Labor Cost	$10,000
MONTHLY Recurring O&M	$ 3,500

Breakdown of the ONE-TIME Equipment Cost:

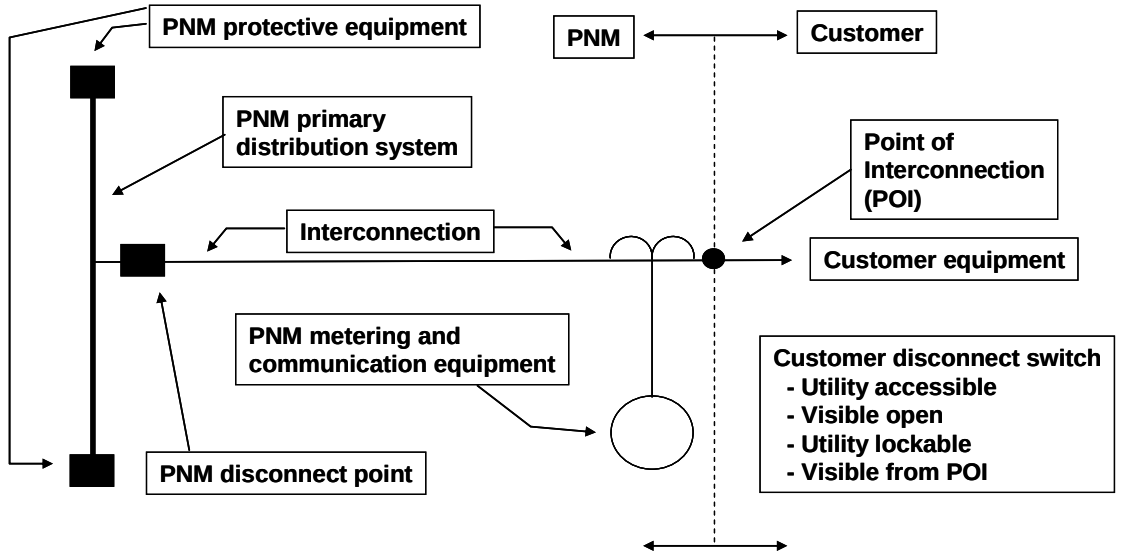
Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$20,000
Channel Bank Equipment	$10,000

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

***Figure 3** – Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



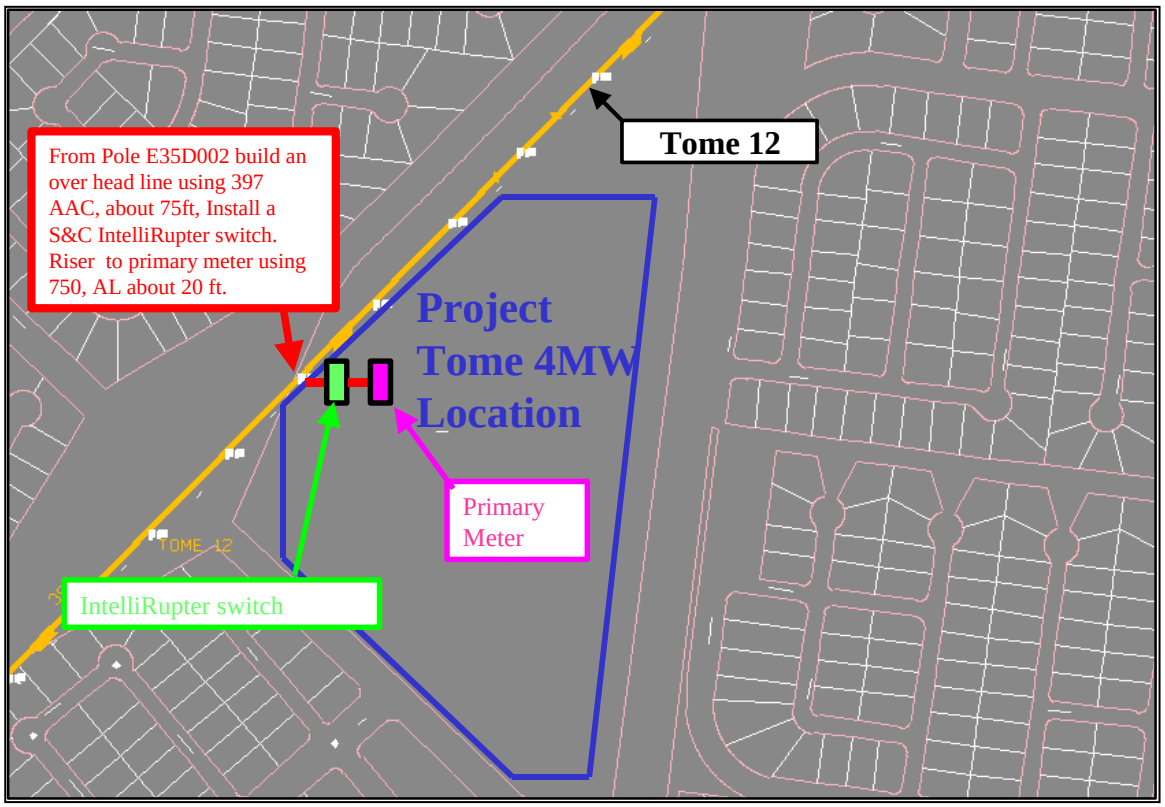
The PNM disconnect point will consist of a SCADA controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project Tome to the PNM distribution system, system upgrades are required. The interconnection consists of:

- Build approximately 75ft of new 397 AAC overhead circuit from Pole E35D002 to the PV site location (See Figure 4)
- Install one S&C IntelliRupter switch (See Figure 4)
- Riser to primary meter, about 20ft, using 750 AL (See Figure 4)

***Figure 4* – System upgrade for Project Tome**



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 8.

Table 8 ***- Project Tome Interconnection Cost***

	ESTIMATED COSTS 2011$	ESTIMATED CONSTRUCTION TIME
PNM disconnect point (IntelliRuptor)	$ 52,000	~ 16 week lead time ~ 3 days to build
Overhead line extension	$ 44,500	~ 16 week lead time ~ 1 weeks to build
Primary metering	$ 25,000	~ 3 week lead time ~ 4 days to build
Environmental	$ 2,889	
Right of Way	$ 13,500	
Communication	$ 45,000	
Communication monthly O&M	$ 3,500	
TOTAL	**$ 182,889** **Plus monthly O&M of $3,500**	**5-6 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple landowners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Distribution Planning performed a screening analysis of Project Tome 4 MVA PV system operating at 100% (unity) power factor and determined there was an adverse impact on the PNM electric distribution system. Two options were presented to mitigate the adverse impact. Option 1 is to operate the Project at a fixed 99% power factor allowing the electric distribution system to operate within the PNM established criteria. Option 2 is to establish an operating procedure that addresses the process to mitigate the adverse impact on voltage. This Study recommends Option 2 and the establishment of an operating procedure for Project Tome.

Analysis shows voltages will remain within the PNM criteria of ANSI C84.1 for normal system conditions. Project Tome has an adverse voltage impact for outage of Tome Substation. This can be mitigated by establishing an operating procedure to reset the Project power factor when Voltages at the POI exceed PNM criteria. There is one remotely controlled capacitor bank on the feeder associated with Project Tome. The remotely controlled capacitor bank on the feeder may be de-energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC may cause the LTC to operate but this is not considered an adverse issue. The Project output may cause a flow of electricity from the distribution system through the substation transformer, but there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductor ratings to be exceeded. The Project contribution to fault current does not adversely impact the protection coordination on Tome Feeder 12, Tome Substation, First Street Feeder 11, First Street Feeder 12, Manzano Feeder 13, or Manzano Substation. Finally, analysis shows that Project Tome output variation will not cause voltage flicker issues on the electric distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Tome and has determined that there are no adverse impacts associated with a 4,000 KVA AC source operating at a 100% (unity) power factor during normal conditions. Project Tome operating at 100% (unity) power factor does have an adverse impact on the PNM electric distribution system during contingent conditions. Voltage control utilizing a different power setting can mitigate this adverse impact. Establishment of an operating procedure is required to address this adverse impact.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Tome Substation is maintained within established PNM voltage, equipment and fault protection criteria. Distribution Planning recommends that an operating procedure be developed and implemented to address identified adverse voltage impacts.

XXXXX

Project Pajarito
5,000 KVA PV Generation

Small Generator Interconnection
System Impact Study

(IA-PNM-2010-05)

December 2010

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution
Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for XXXXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

The XXXXX submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 5,000 KVA AC to the Public Service of New Mexico ("PNM") distribution primary system. The request is identified as "Project Pajarito" and would be connected to South Coors Feeder 12. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures ("SGIP") for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study ("Study") was performed by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts ("Distribution Planning").

The estimated cost of connecting Project Pajarito to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRuptor)	$XXXXX	~ 16 week lead time ~ 3 days to build
Overhead line extension	$XXXXX	~ 16 week lead time ~ 2 weeks to build
Primary metering	$XXXXX	~ 3 week lead time ~ 4 days to build
Right of Way	$XXXXX	
Communication	$XXXXX	
Communication monthly O&M	$XXXXX	
TOTAL	**$XXXXX** **Plus monthly O&M of** **$XXXXX**	**5-6 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

The application notes that the Satcon Powergate Plus PVS 500 inverter will be used for the Project. This inverter is UL 1741 compliant.

This Study evaluates the electrical system impacts from a request using an electric generation source connected to the distribution primary system. The photovoltaic ("PV") generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Distribution Planning performed a screening analysis of the Project Pajarito 5 MVA PV system operating at 100% (unity) power factor and determined there was no adverse impact on the PNM electric distribution system when the facility is connected to South Coors Feeder 12. The screening analysis concluded that Project Pajarito operating at a 97.5% power factor mitigated adverse impacts when the facility is connected to Sewer Plant Feeder 14. PNM recommends Project Pajarito operate at a fixed 97.5% power factor when the facility is connected to Sewer Plant Feeder 14. The Project will be injecting 4,875 KW into the electric distribution system and absorbing 1,111 KVAR from the electric distribution system during contingency conditions.

Project Pajarito does not have an adverse impact on the PNM electric distribution system when operating with South Coors Feeder 12 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to clouds were found to not cause voltage flicker problems.
4. Project output does not cause conductor ratings to be exceeded. An upgrade of 3,110 ft of single-phase to three-phase is included in the interconnection costs.
5. Remotely controlled capacitor banks on the feeder are normally de-energized and Project Pajarito does not cause the capacitors to be energized.
6. The Project contribution to fault current does not require the South Coors Feeder 12, South Coors Substation, Sewer Plant Feeder 14 or Sewer Plant Substation protection scheme be modified.
7. Project output may cause a flow of electricity from the distribution system through the South Coors or Sewer Plant substation transformer. There is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Pajarito and has determined that there are no adverse impacts associated with a 5,000 KVA AC source connected to South Coors Feeder 12 for the normal system configuration or to Sewer Plant Feeder 14 for the contingent system configuration when operating at a fixed 97.5% power factor. The project will be injecting 4,875 KW into the electric distribution system and absorbing 1,111 KVAR from the electric distribution system.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on South Coors Feeder 12 is maintained within established PNM voltage, equipment and fault protection criteria.

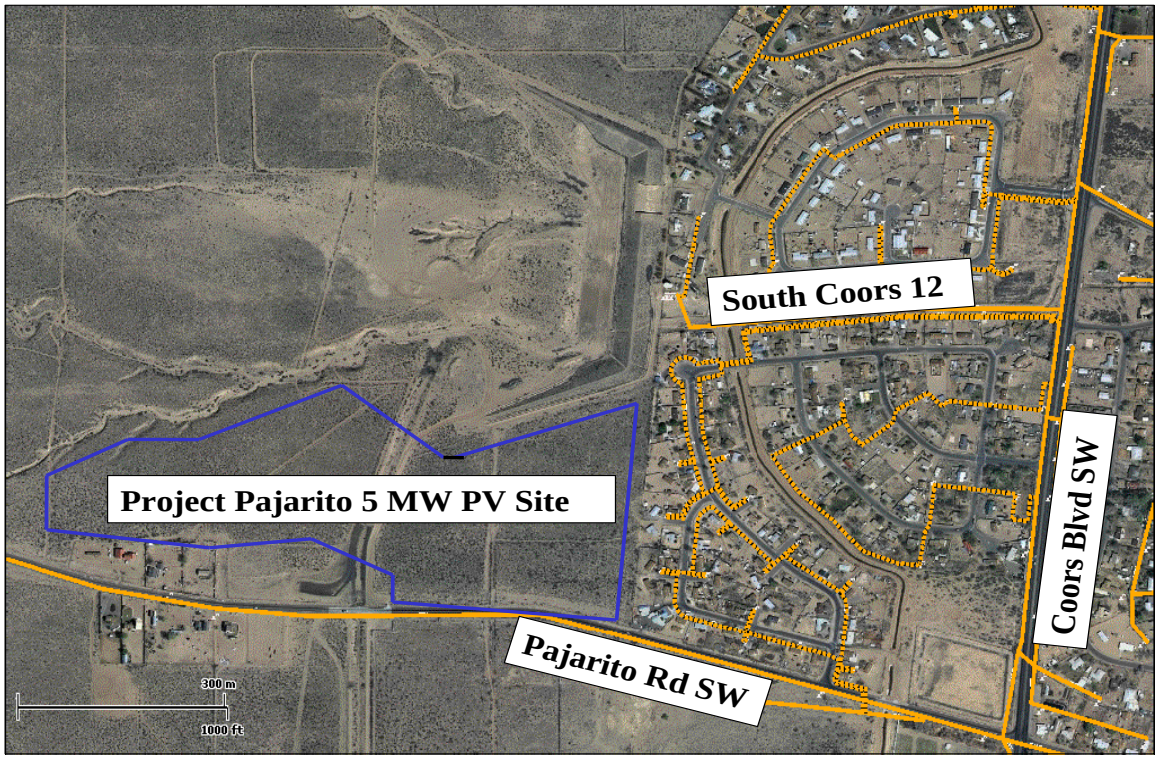
1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a PV electric generation source connected to the PNM distribution primary system identified as Project Pajarito. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage and current produced by the PV equipment to AC voltage and current. Electric system impacts considered were voltage, equipment ratings, and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Pajarito proposes to connect a 5,000 KVA AC PV facility to South Coors Substation Feeder 12 in Bernalillo County, NM. The Project will be located 0.5 miles west of South Coors Blvd and Pajarito Rd in Bernalillo County as shown in Figure 1. The circuit distance from South Coors Substation to Project Pajarito point of interconnection ("POI") is about 11,967 ft or 2.27 miles.

Figure 1 – Project Pajarito Location



3.0 SYSTEM CONFIGURATION

Project Pajarito is connected to South Coors Substation Feeder 12. The project will be normally served from South Coors Feeder 12 with contingency back up provided by Sewer Plant Feeder 14 via South Coors Feeder 11 and South Coors Feeder 14. Table 1 shows the rating of South Coors Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
South Coors	22.4	23.4	24.9	115-12.47
Sewer Plant	22.4	24.0	26.8	115-12.47

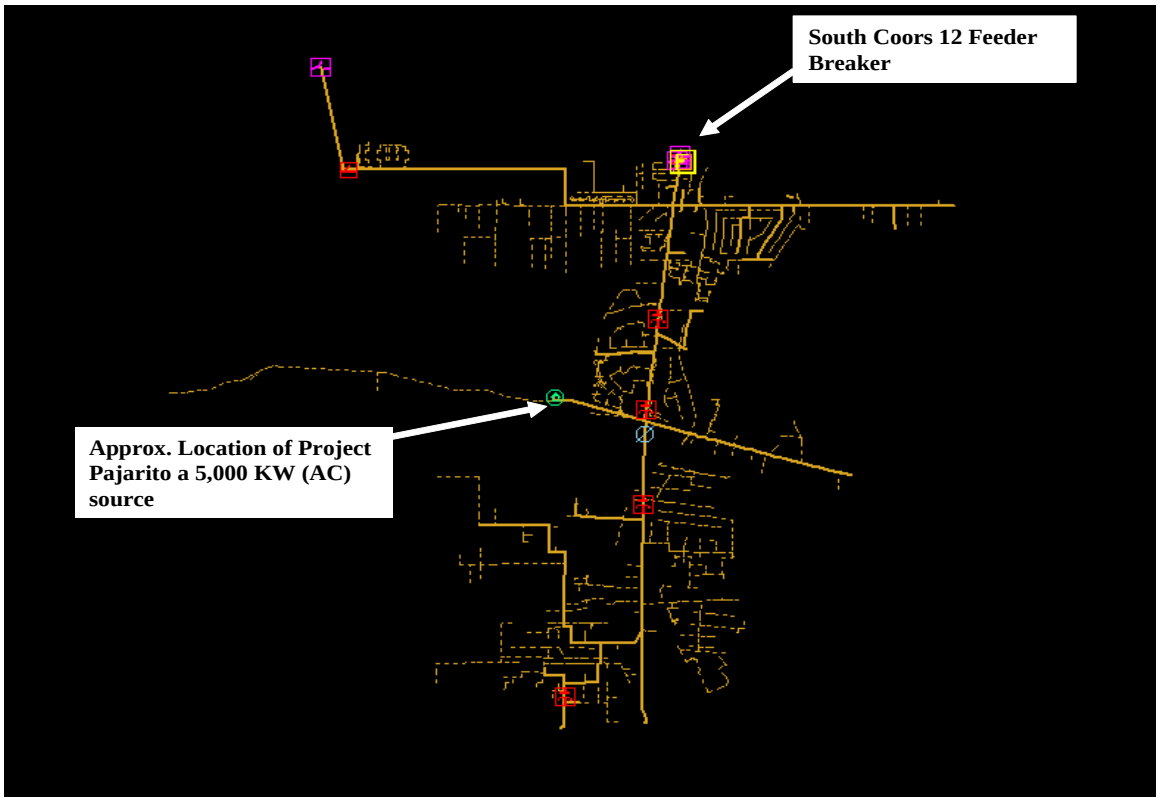
Table 2 shows the non-coincident 2009 peak summer loads for South Coors and Sewer Plant Substation and feeders.

***Table 2* – Summer 2009 (June-August) Non-coincident Peak Loads**

Feeder	Summer 2009 Non-coincident Peak Load					% Power Factor
	Date	Time	KW	KVAR	KVA	
South Coors						
South Coors 11	07/08/09	6:45 PM	5,793	-412	5,808	-99.7
South Coors 12	07/13/09	9:00 PM	5,656	-538	5,682	-99.6
South Coors 13	07/11/09	4:45 PM	5,624	1,277	5,767	97.5
South Coors 14	07/13/09	6:00 PM	5.962	2,068	6,310	94.5
South Coors Sub	07/08/09	7:00 PM	21,062	1,256	21,099	99.8
Sewer Plant						
Sewer Plant 11	07/14/09	3:00 PM	844	-1,498	1,179	-49.1
Sewer Plant 12			0	0	0	0
Sewer Plant 13	07/02/09	6:30 AM	3,925	2,237	4,517	86.9
Sewer Plant 14	07/20/09	1:30 PM	5,329	-1,678	5,587	-95.4
Sewer Plant Sub	07/20/09	1:00 PM	7,735	-1,678	7,915	-97.7

Figure 2 is a picture of the distribution feeder used in the Advantica Synergee modeling program.

Figure 2 – Synergee model of South Coors Feeder 12



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the South Coors Feeders 11, 12, 14 and Sewer Plant Feeder 14 are shown in Table 3:

Table 3 *– Max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
South Coors 11								
July 8, 2009	7 PM	5,635	-506	5,658	-99.6	275	251	246
June 19, 2009	2 PM	791	-274	837	-94.5	39	49	29
South Coors 12								
July 13, 2009	7 PM	5,487	-464	5,506	-99.6	267	254	223
May 24, 2009	7 AM	1,920	-654	2,028	-94.9	94	94	87
South Coors 14								
July 13, 2009	6 PM	5,962	2,068	6,310	94.5	303	252	300
May 3, 2009	7 AM	897	-211	921	-97.4	45	35	45
Sewer Plant 14								
July 16, 2009	2 PM	5,223	169	5,225	99.9	233	276	209
May 30, 2009	7 AM	1,699	-781	1,869	-90.9	87	99	69

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Table 4 lists the capacitors on the four feeders and their status at the minimum and maximum load times.

***Table 4* – Status of capacitors**

Capacitor	KVAR Size	Fixed or Switched	Status		
			Min load	Max load	Non - Coincident
South Coors 11					
C1155	600	F	ON	ON	ON
C453	600	F	ON	ON	ON
C64	600	F	ON	ON	ON
C687	1,800	S	OFF	OFF	OFF
C731	600	F	ON	ON	ON
C936	1200	S	OFF	ON	ON
South Coors 12					
C324	600	F	ON	ON	ON
C624	1,800	S	OFF	OFF	ON
C663	600	F	ON	ON	ON
C937	1,200	S	OFF	OFF	OFF
South Coors 14					
C1228	1,200	S	ON	ON	ON
Sewer Plant 14					
C1168	600	F	ON	ON	ON
C1169	1,200	S	OFF	OFF	OFF
C416	600	F	ON	ON	ON
C418	600	F	ON	ON	ON
C504	1,800	S	OFF	OFF	ON
C896	1,200	S	OFF	ON	ON

4.1 Screen for PV system impacts associated with power factor setting

Scenario's reviewed by this study define an inverter based distributed generation facility operating with a power factor other then unity to be a facility that is absorbing or importing reactive power at the POI. Inverter control systems can be adjusted to allow the PV system to absorb reactive power (Vars) from the distribution system. Recommendations to absorb reactive power at the POI, to mitigate the Project voltage rise impact on the electric distribution system, will be included in all remaining operating conditions to review the ability of the facility to maintain ANSI C84.1 voltage criteria limits.

The electric distribution system was screened to determine if there are any adverse impacts associated with Project Pajarito injecting energy into the distribution system at the POI. Project Pajarito was evaluated operating at a 100% (unity) power factor to determine if system criteria limits were violated. The system was evaluated with and without Project Pajarito for maximum and minimum load during normal and contingency conditions to ensure the distribution system operated within the voltage criteria limits of ANSI C84.1. Operating conditions resulting in voltages outside of the criteria limits will require voltage control utilizing a different power factor setting on the PV project.

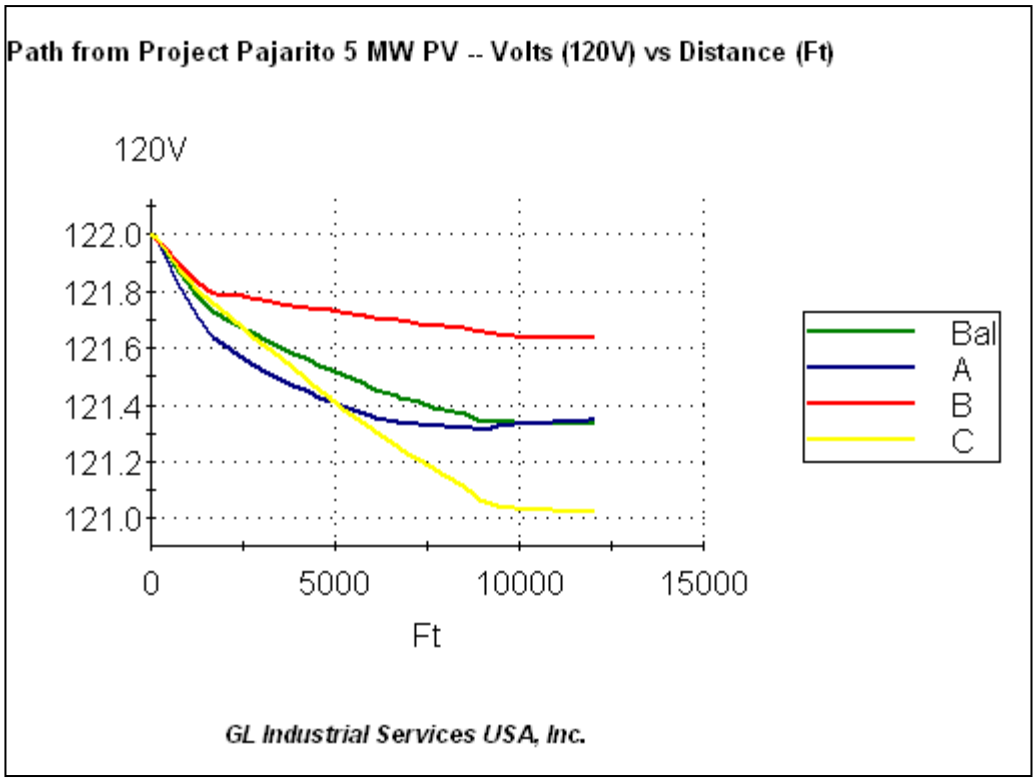
4.2 Voltage impacts on the transmission system

Project Pajarito operating at a 100% power factor will be injecting 5,000 KW into the distribution system at the POI. The peak load on South Coors Substation (see table 2) is greater than the Project rated output. The minimum load on the South Coors Substation does not typically fall below 5 MW so transmission related issues are not anticipated to be associated with Project Pajarito at maximum or minimum output.

4.3 Voltage impacts for maximum daylight hours load

The South Coors Feeder 12 voltage for the feeder daylight hours maximum load for 2009 with and without Project Pajarito, per the Synergee model, are shown in graphs 1 and 2.

Graph 1 – South Coors Feeder 12 voltage drop from South Coors Substation to Project Pajarito POI for daylight hours maximum load on July 13, 2009. Project Pajarito is OFF.

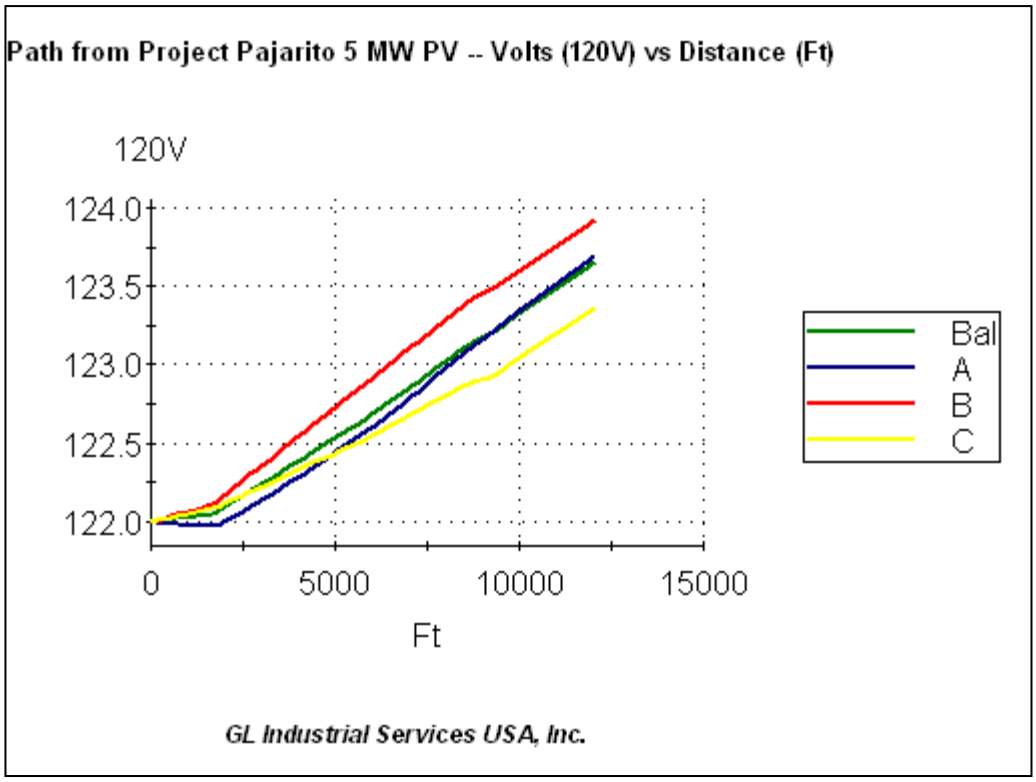


The model voltages at the point of interconnection are:

Phase A – 121.3 volts Phase B – 121.6 volts Phase C – 121.0 volts Balanced – 121.3 volts

The voltages on South Coors Feeder 12 prior to the installation of Project Pajarito are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR and 1,200 KVAR switched capacitors being de-energized.

Graph 2 – South Coors Feeder 12 voltage drop from South Coors Substation to Project Pajarito POI for daylight hours maximum load on July 13, 2009. Project Pajarito is ON at a 100% power factor.



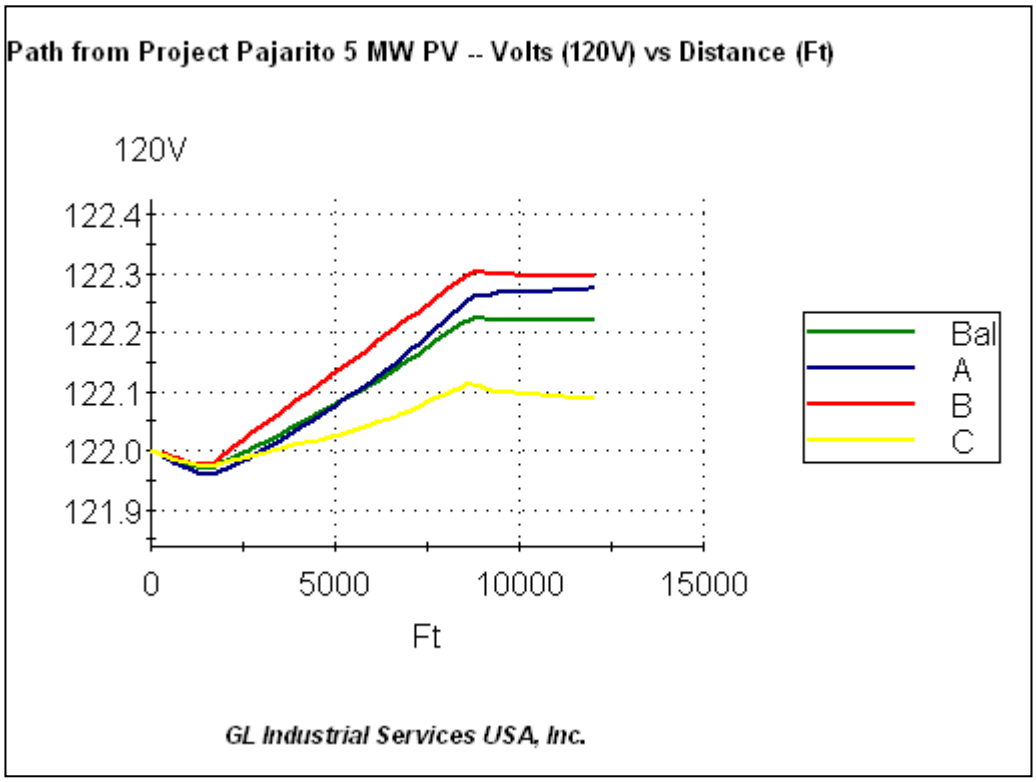
The model voltages at the point of interconnection are:
Phase A – 123.7 volts Phase B – 123.9 volts Phase C – 123.4 volts Balanced – 123.7 volts

The voltage on South Coors Feeder 12 after the installation of Project Pajarito operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR and 1,200 KVAR switched capacitors being de-energized.

4.4 Voltage impacts for minimum daylight hours load

The South Coors Feeder 12 voltage for the feeder daylight hours minimum load for 2009 with and without Project Pajarito, per the Synergee model, are shown in Graphs 3 and 4.

Graph 3 – South Coors Feeder 12 voltage drop from South Coors Substation to Project Pajarito POI for daylight hours minimum load on May 24, 2009. Project Pajarito is OFF.

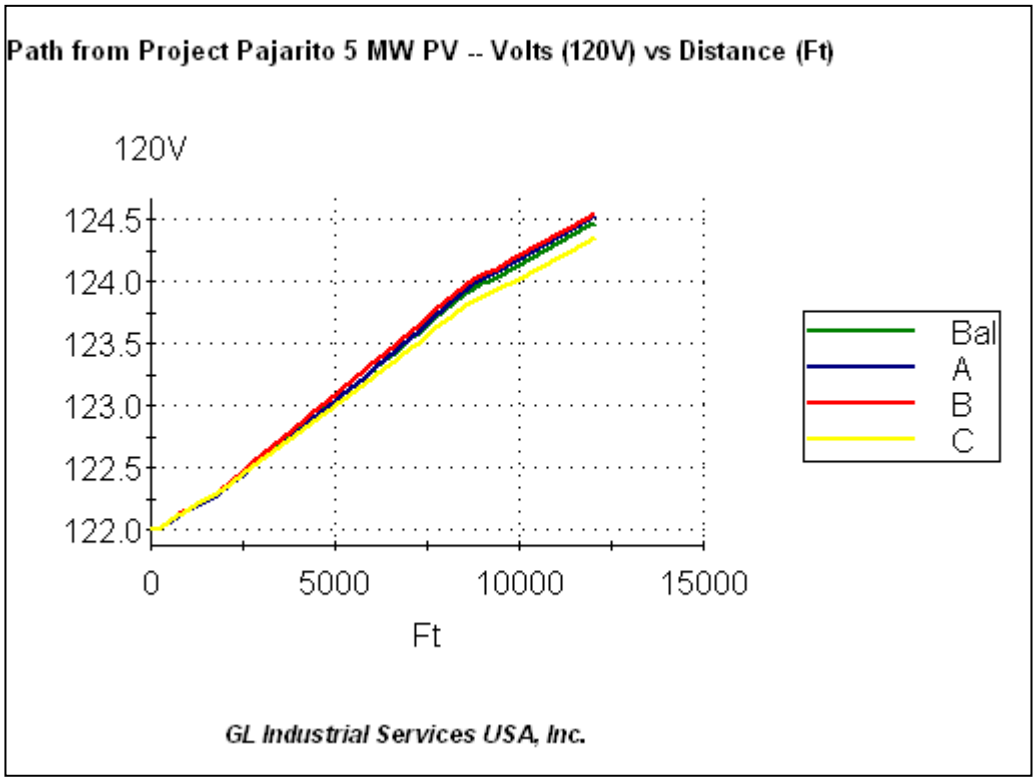


The model voltages at the point of interconnection are:

Phase A – 122.3 volts Phase B – 122.3 volts Phase C – 122.1 volts Balanced – 122.2 volts

The voltages on South Coors Feeder 12 prior to the installation of Project Pajarito are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR and 1,200 KVAR switched capacitors being de-energized.

Graph 4 – South Coors Feeder 12 voltage drop from South Coors Substation to Project Pajarito POI for daylight hours minimum load on May 24, 2009. Project Pajarito is ON at a 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 124.5 volts Phase B – 124.5 volts Phase C – 124.4 volts Balanced – 124.5 volts

The voltages on South Coors Feeder 12 after the installation of Project Pajarito operating at a 100% power factor increase but stay with the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR and 1,200 KVAR switched capacitors being de-energized.

In conclusion, Project Pajarito operating at a 100% power factor output does cause the voltage on South Coors Feeder 12 at the Project POI to increase but the voltage stays within the PNM criteria of ANSI C84.1.

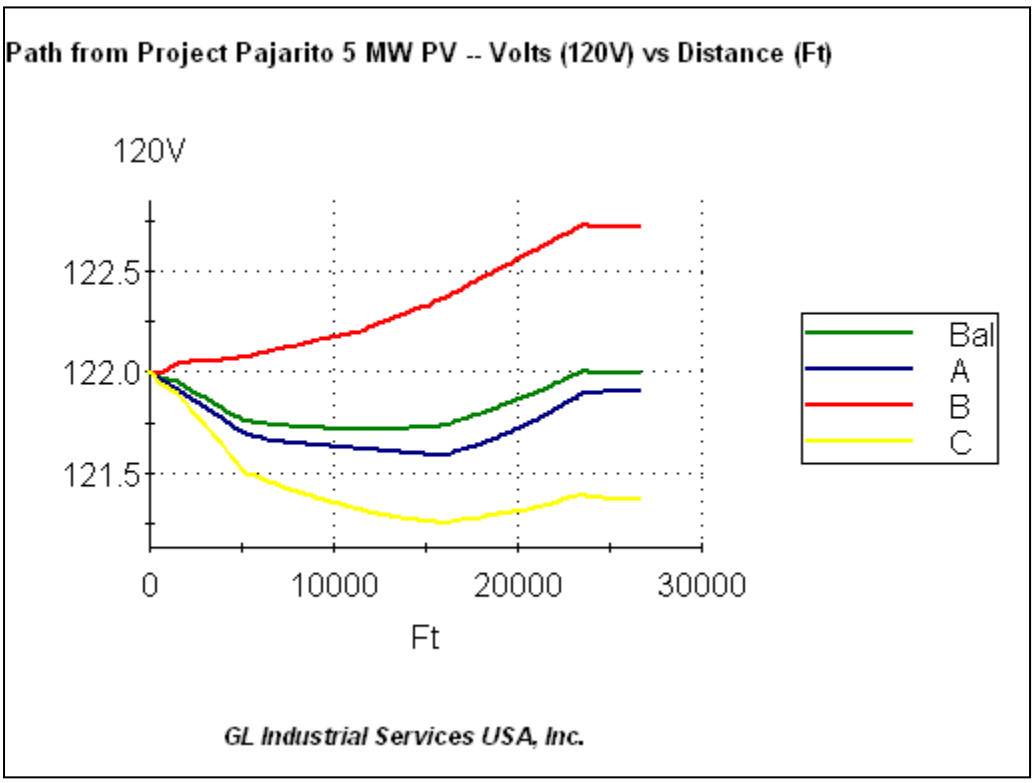
4.5 Voltage impacts during an outage of South Coors Substation

Sewer Plant Feeder 14 backs up South Coors Feeder 12 when South Coors Substation is out-of-service due to maintenance or equipment failure. The minimum and maximum loading on Sewer Plant Feeder 14, and South Coors Feeders 11, 12, and 14 for the hours of 7AM to 7PM is shown in Table 3. For the condition of South Coors Substation out-of-service, 100% of South Coors Feeder 12 gets transferred to Sewer Plant Substation through 2% of Sewer Plant Feeder 14, 35% of South Coors Feeder 11 and 34% of South Coors 14.

4.5.1 Voltage impacts for daylight hours minimum load during an outage of South Coors Substation

The Sewer Plant Feeder 14 voltage for daylight hours minimum load for 2009 with and without Project Pajarito, per the Synergee model, are shown in Graphs 5, 6, and 7.

Graph 5 – Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours minimum load on May 24, 2009. Project Pajarito is OFF.

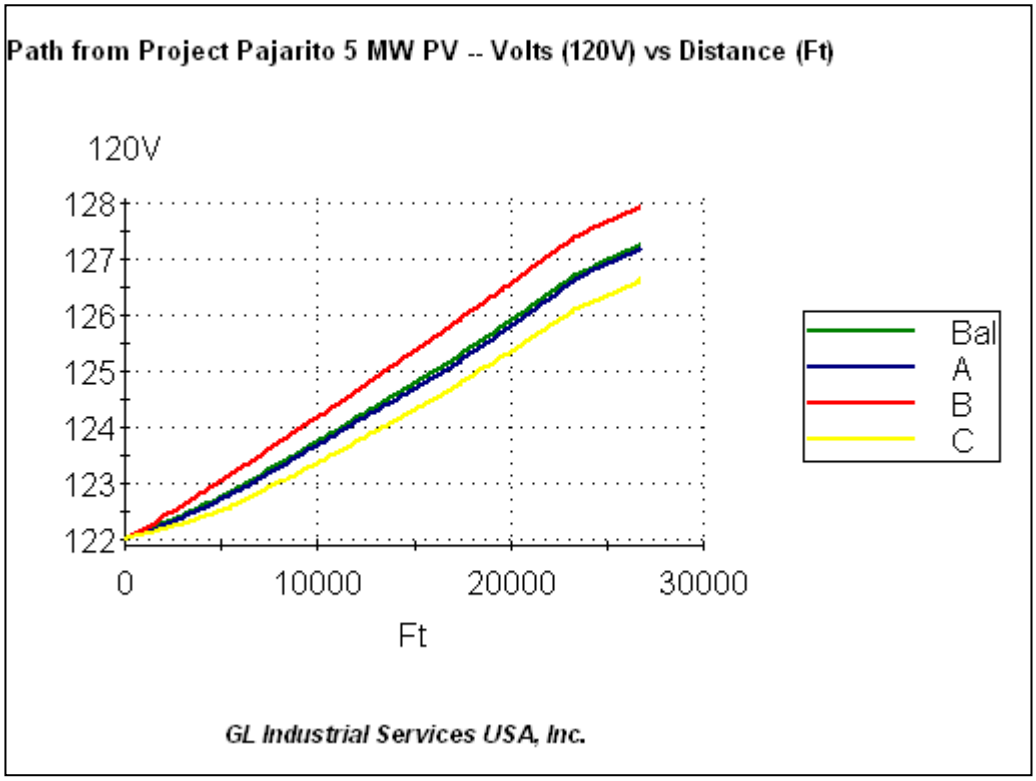


The model voltages at the point of interconnection are:

Phase A – 121.9 volts Phase B – 122.7 volts Phase C – 121.4 volts Balanced – 122.0 volts

The voltages on Sewer Plant Feeder 14 prior to the installation of Project Pajarito are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR and 1,200 KVAR switched capacitors being de-energized.

Graph 6 – Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours minimum load on May 24, 2009. Project Pajarito is ON at a 100% power factor



The model voltages at the point of interconnection are:

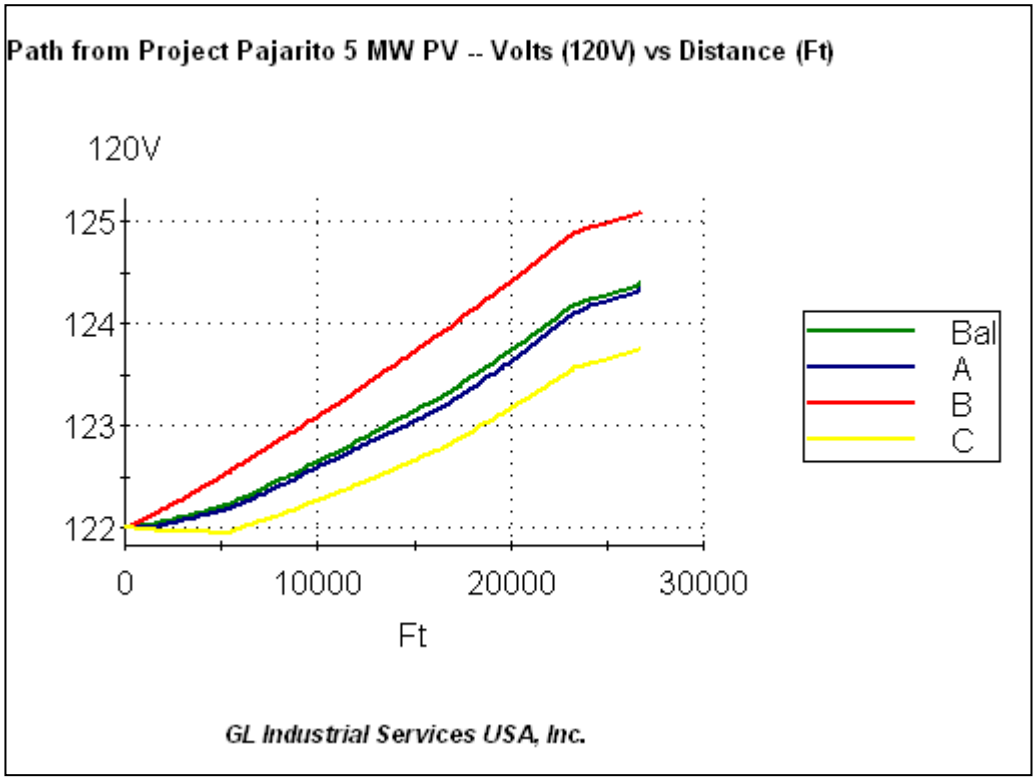
Phase A – 127.2 volts Phase B – 128.0 volts Phase C – 126.6 volts Balanced – 127.3 volts

The voltages on Sewer Plant Feeder 14 after the installation of Project Pajarito operating at a 100% power factor are above the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are unacceptable. This model is based on the 1,800 KVAR and 1,200 KVAR switched capacitors being de-energized.

Project Pajarito has an adverse impact on the PNM electric distribution system when operating at a 100% (unity) power factor. Voltage control utilizing a different power factor setting on the Project is necessary.

Setting Project Pajarito to a 97.5% power factor such that the Project is injecting 4,875 KW into the distribution system at the POI and absorbing 1,111KVAR from the distribution system at the POI is required to mitigate voltages above the ANSI C84.1 criteria limits. Graph 7 is the same condition as shown in Graph 6 except Project Pajarito is modeled with a 97.5% power factor.

Graph 7 – Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours minimum load on May 24, 2009. Project Pajarito is ON at a 97.5% power factor



The model voltages at the point of interconnection are:

Phase A – 124.3 volts Phase B – 125.1 volts Phase C – 123.8 volts Balanced – 124.4 volts

The voltages on Sewer Plant Feeder 14 after the installation of Project Pajarito operating at a 97.5% power factor are below the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are acceptable. This model is based on the 1800 KVAR and 1200 KVAR switched capacitor banks on South Coors Feeder 12 being de-energized.

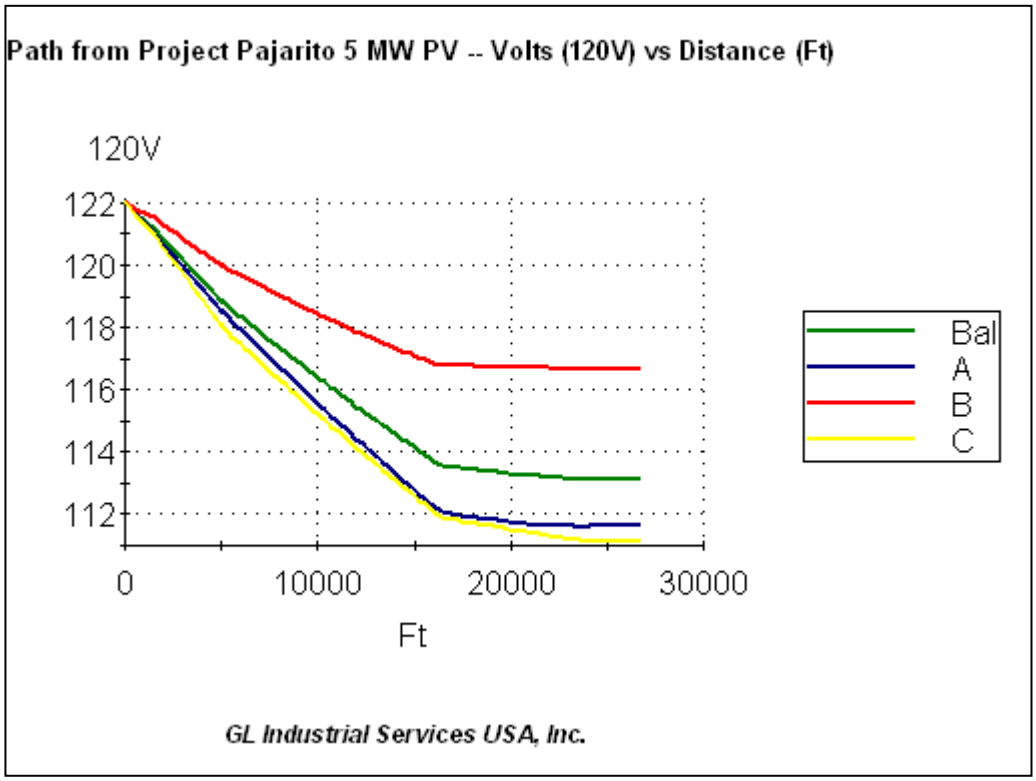
In conclusion, Project Pajarito operating at a 100% (unity) power factor has an adverse impact on the PNM electric distribution system during minimum load periods and when Sewer Plant Feeder 14 is supporting South Coors Feeder 12 due to South Coors Substation being out-of-

service. Voltages at the Project POI are above the ANSI C84.1 upper limit and are unacceptable. Voltage control utilizing a different power factor setting on the Project is necessary. Setting Project Pajarito to a 97.5% power factor such that the Project is injecting 4,875 KW into the distribution system at the POI and absorbing 1,111 KVAR from the distribution system at the POI is required to mitigate voltage above the ANSI C84.1 criteria limits. Project Pajarito operating at a 97.5% power factor output does cause the voltage on Sewer Plant Feeder 14, when supporting South Coors Feeder 12 due to South Coors Feeder 12 being out-of-service, to increase but the voltage stays within the PNM criteria of ANSI C84.1.

4.5.2 Voltage impacts for daylight hours maximum load during an outage of South Coors Substation

The South Coors Feeder 12 voltage for the feeder maximum daylight hours load for July 13, 2009 with and without Project Pajarito, per the Synergee model, are shown in Graphs 8, 9, and 10.

Graph 8- Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours maximum load on July 13, 2009. Project Pajarito is OFF. Two RCCS capacitors are OFF



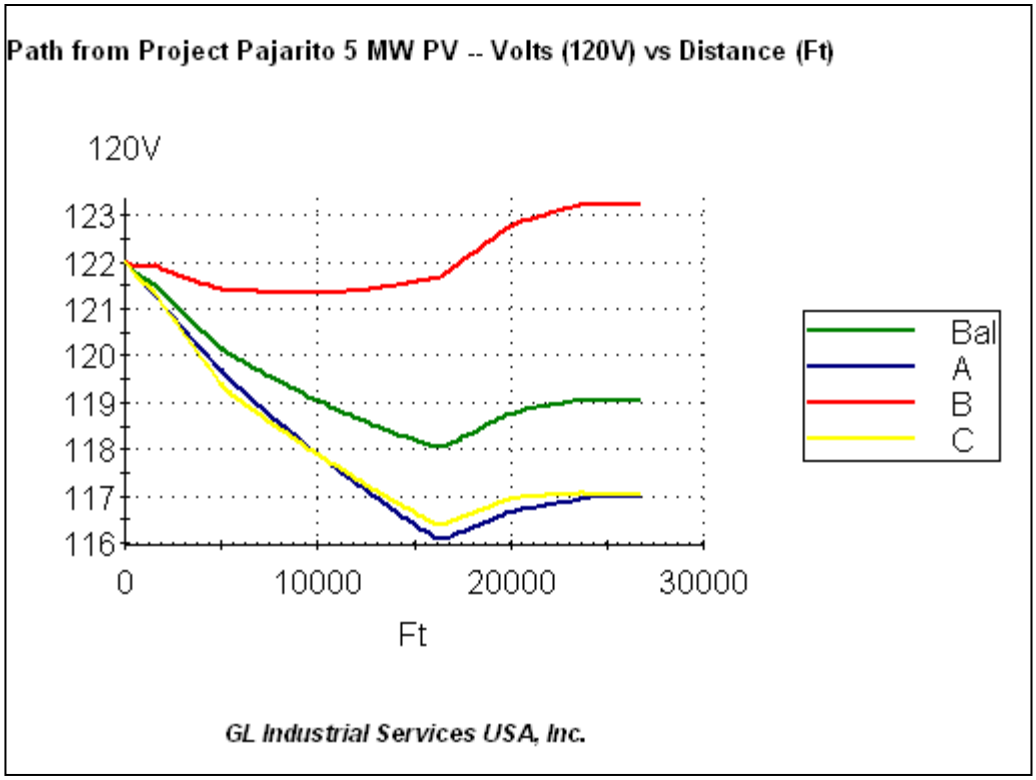
The model voltages at the point of interconnection are:

Phase A – 111.6 volts Phase B – 116.6 volts Phase C – 111.1 volts Balanced –113.1 volts

The voltages on Sewer Plant Feeder 14 for the loss of South Coors Substation contingency prior to the installation of Project Pajarito are below the PNM voltage criteria ANSI C84.1 Range A service voltage at the POI and are unacceptable. This model is based on the 1800 KVAR and

1200 KVAR switched capacitor banks on South Coors Feeder 12 being de-energized. Turning on the Radio Control Central Station ("RCCS") capacitor banks on South Coors Feeder 12 will be needed at maximum loading time frames as shown in Graph 9.

Graph 9- Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours maximum load. Project Pajarito is OFF. Two RCCS capacitors are ON.

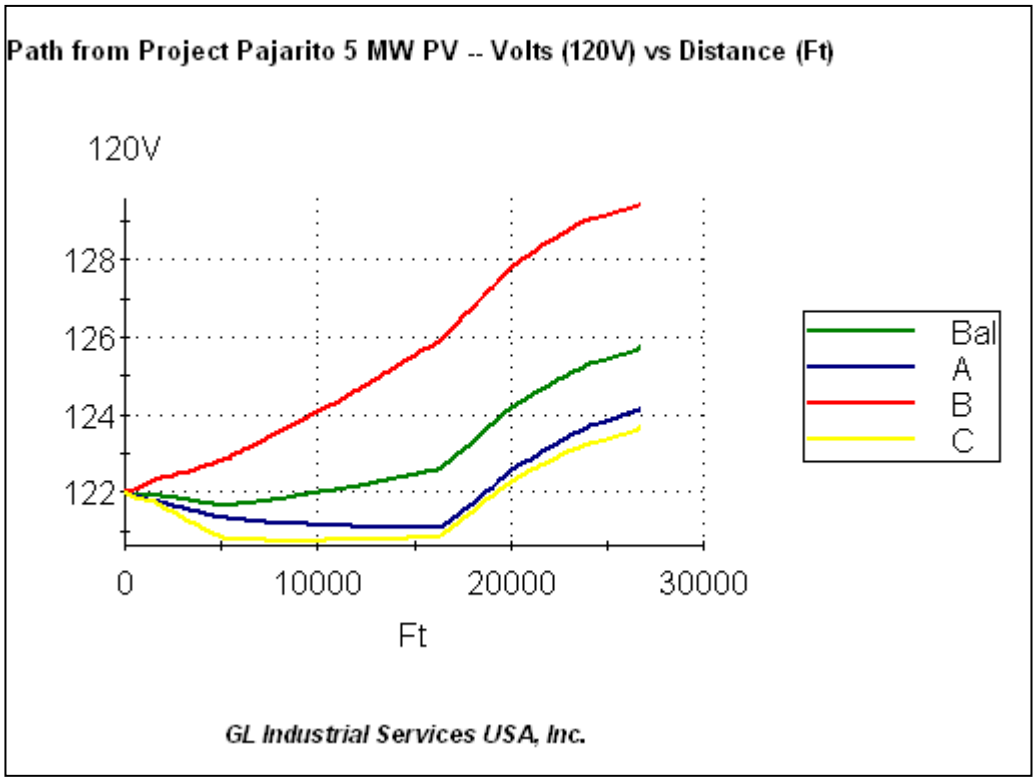


The model voltages at the point of interconnection are:

Phase A – 117.0 volts Phase B – 123.2 volts Phase C – 117.0 volts Balanced – 119.0 volts

The voltages on Sewer Plant Feeder 14 for the loss of South Coors Substation contingency prior to the installation of Project Pajarito with the RCCS capacitor banks on South Coors Feeder 12 turned ON, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on capacitors ON for voltage support during the outage of the South Coors Substation.

Graph 10 – Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours maximum load on July 13, 2009. Project Pajarito is ON at a 100% power factor. Two RCCS capacitor banks turned ON.

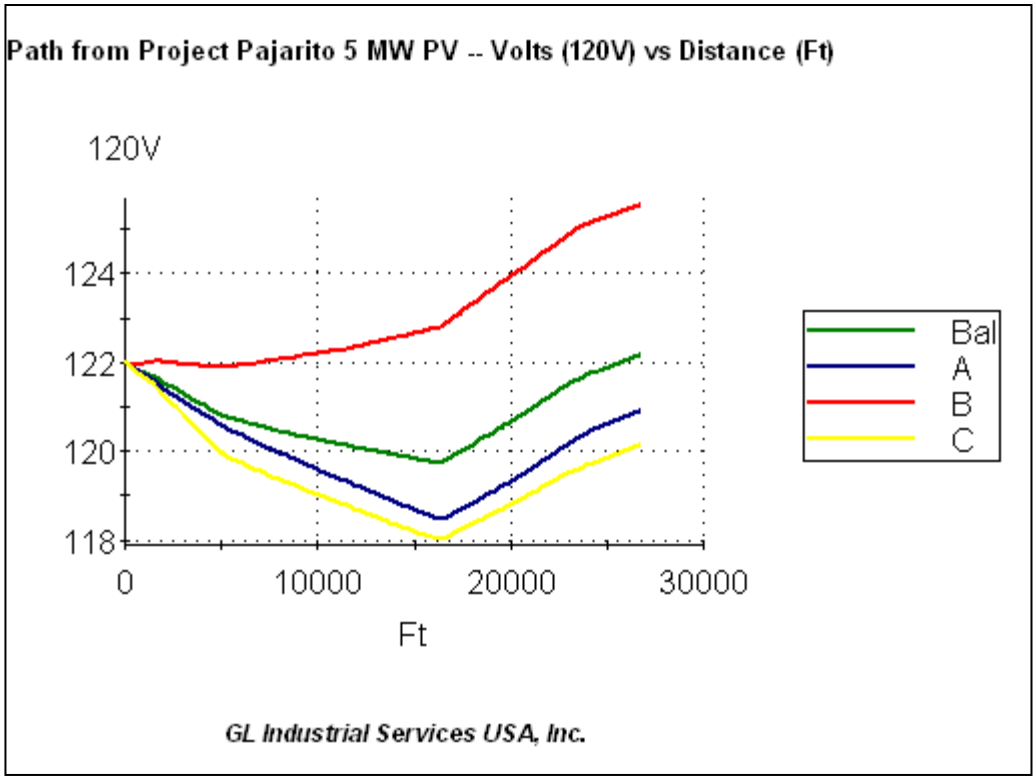


The model voltages at the point of interconnection are:

Phase A – 124.2 volts Phase B – 129.4 volts Phase C – 123.7 volts Balanced – 125.7 volts

The voltages on Sewer Plant Feeder 14 after the installation of Project Pajarito operating at a 100% power factor with the RCCS capacitor banks on South Coors Feeder 12 turned ON, are above the PNM voltage criteria (ANSI C84.1) at the POI and are unacceptable. This model is based on the RCCS capacitor banks turned ON for voltage support during the outage of the South Coors Substation. To improve the voltage one of the RCCS capacitor banks must be de-energized.

Graph 11 – Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours maximum load on July 13, 2009. Project Pajarito is ON at a 100% power factor. 1200 RCCS capacitor bank turned ON and 1800 RCCS capacitor bank turned OFF.

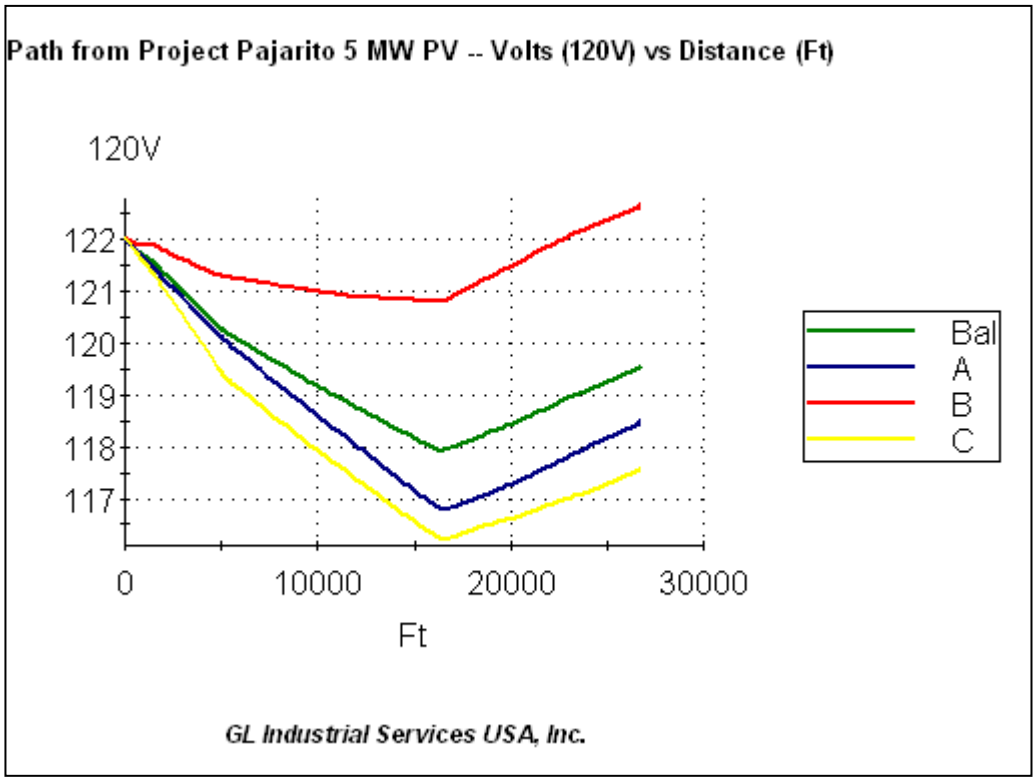


The model voltages at the point of interconnection are:

Phase A – 120.9 volts Phase B – 125.6 volts Phase C – 120.1 volts Balanced – 122.2 volts

The voltages on Sewer Plant Feeder 14 after the installation of Project Pajarito with the 1200 RCCS capacitor bank turned ON and the 1800 RCCS capacitor bank turned OFF on South Coors Feeder 12, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 12 – Sewer Plant Feeder 14 voltage drop from Sewer Plant Substation to Project Pajarito POI for daylight hours maximum load on July 13, 2009. Project Pajarito is ON at a 100% power factor. Two RCCS capacitor banks turned OFF.



The model voltages at the point of interconnection are:

Phase A – 118.5 volts Phase B – 122.6 volts Phase C – 117.6 volts Balanced – 119.6 volts

The voltages on Sewer Plant Feeder 14 after the installation of Project Pajarito operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) Range A at the POI and are acceptable. This model is based on the 1800 KVAR and 1200 KVAR switched capacitor banks on South Coors Feeder 12 being de-energized.

In conclusion, prior to the installation of Project Pajarito (with the two RCCS capacitor banks de-energized on South Coors Feeder 12) during contingent conditions voltages are below ANSI C84.1 Range A and are unacceptable. The two RCCS switched capacitor banks normally on South Coors Feeder 12 must be energized for voltage support. Project Pajarito operating at a 100% (unity) power factor output with the two RCCS capacitor banks energized, does cause the

voltage on Sewer Plant 14 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

After the installation of Project Pajarito, with the two RCCS capacitor banks normally on South Coors Feeder 12 energized during contingent conditions, the voltages are above the PNM voltage criteria (ANSI C84.1) Range A and are unacceptable. De-energizing the 1800 RCCS capacitor bank (Shown in Graph 11) brings the voltages below the PNM voltage criteria (ANSI C84.1) range A upper voltage limit of 126 volts and is marginally acceptable. De-energizing both RCCS capacitor banks on South Coors Feeder 12 (Shown in Graph 12) shows that voltages are acceptable.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Pajarito is served by South Coors Feeder 12, and does not have a voltage regulator installed on the feeder. The substation LTC is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 120.5 volts and will reduce the voltage if the substation bus is above 123.5 volts.

Synergee modeling showed that the voltage variance at the substation due to a 5,000 KVA source on the feeder would be about 0.1 volts for high or low load periods. This voltage variance will be insufficient to cause the substation LTC to operate for high or low load on the feeder.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (“GE”) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Pajarito POI is shown in Section 4.0. Table 5 summarizes the balanced voltage and the calculated voltage flicker. Table 6 is based on the GE flicker graph.

Table 5 ***- Voltage flicker on South Coors Feeder 12 due to Project Pajarito***

	POI Voltage South Coors Feeder 12 Loading	
	Minimum	**Maximum**
Without Project	122.2	121.3
With Project	124.5	123.7
% Voltage Flicker	**1.88**	**1.98**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 6 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
1.88	3/hour	2/minute
1.98	3/hour	2/minute

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 5 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 6. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Pajarito POI to the substation were reviewed using the Synergee feeder model with and without Project Pajarito's maximum output of 5,000 KVA AC.

There were no conductor loading problems from the POI to the substation on South Coors Feeder 12 for the normal system configuration or on Sewer Plant 14 for the contingent system configuration with and without Project Pajarito during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the RCCS program. The RCCS program polls the System Control and Data Acquisition ("SCADA") system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. For this study, Project Pajarito was found to cause adverse impacts on the system at 100% power factor during contingent conditions. Project Pajarito is recommended to operate at a 97.5% power factor during contingent conditions and will be injecting 4,875 KW into the distribution system and absorbing 1,111 KVAR from the distribution system. When the inverter is operating the power factor of the distribution feeder will be affected.

RCCS adjusts the power factor of individual feeders by energizing or de-energizing switched capacitors. South Coors Feeder 12 has one 1800 KVAR RCCS capacitor bank, one 1200 KVAR RCCS capacitor bank, and two 600 KVAR fixed capacitor banks. The Summer 2009 peak load on the feeder was 5,656 KW – j 538 KVAR or 5,682 KVA at a 99.6% leading power factor (See Table 2) with the 1,200 RCCS capacitor bank de-energized and the 1,800 RCCS capacitor bank energized. Project Pajarito at a 97.5% power factor would change the apparent feeder loading to 781 KW + j 573 KVAR or 967 KVA at a 81% lagging power factor.

The new power factor on South Coors Feeder 12 exceeds the RCCS power factor control point. The RCCS control settings result in no capacitors being energized. During an outage of South Coors Substation, South Coors Feeder 12 is carried by Sewer Plant 14 via South Coors Feeder 11 and South Coors Feeder 14. The screening evaluation (Section 4.5) identified a low voltage issue requiring the de-energized 1,800 KVAR and 1,200 KVAR capacitors to be energized prior to the installation of Project Pajarito. The contingent loading on Sewer Plant 14 is 12,273 KW – j 1,605 KVAR. Project Pajarito 4,875 KW + j 1,111 KVAR will change the apparent feeder loading to 7,398 KW – j 494 KVAR. Voltages were reviewed assuming the two switched capacitors are energized along with the installation of Project Pajarito, operating with a unity power factor and no voltage issues associated with this adjusted demand, were identified. Light load conditions (Graph 6) did identify voltages at the POI that are unacceptable and required power factor correction to mitigate high voltage conditions.

9.0 PROTECTION

9.1 Normal Configuration

South Coors Substation Feeder 12 is protected by a 1200 amp breaker in metal clad switchgear with three GE, IAC77 phase overcurrent relays and an IAC53 ground overcurrent relay. There is also a GE, NLR reclosing relay. The switchgear bus and feeder backup protection is three GE, IAC53 phase relays and a GE, IAC53 ground relay. The transformer protection is three GE, STD differential relays. The Pajarito Project PV system is connected to the system approximately 2.27 miles from the substation. Approximately 0.65 miles from the Pajarito Project PV system, there is a 100 amp three-phase hydraulic Recloser.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 278 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at the recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no

locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 5MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

The Pajarito Project does not require any system protection improvements to be made to the South Coors Substation Feeder 12 under normal configuration.

9.2 Contingency Configuration

Sewer Plant Substation Feeder 14 is protected by a 1200 amp breaker in metal clad switchgear with a GE, IAC77 phase overcurrent relay and an IAC53 ground overcurrent relay. There is also a GE, NLR reclosing relay. The switchgear bus and feeder backup protection is a GE, IAC53 phase relay and a GE, IAC53 ground relay. The transformer protection is three GE, IJD differential relays. The Pajarito Project PV system will be approximately 5.07 miles from the substation. There are two 100 amp three-phase hydraulic recloser and one three-phase electronic recloser, 0.65, 5.08 and 5.25 miles away, respectively from the Pajarito Project PV system.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 278 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the reclosers. The available fault current at each recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 5MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

The Pajarito Project does not require any system protection improvements to be made to the Sewer Plant Substation Feeder 14 under contingency configuration.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

During normal conditions Project Pajarito operates at 100% (unity) power factor, however during contingent conditions Project Pajarito has an adverse impact on the system and operates at a 97.5% power factor, which will inject 4,875 KW into the distribution system at POI and absorb 1,111 KVAR from the distribution at the POI. Project Pajarito output exceeds the minimum load on South Coors Feeder 12 during daylight hours for normal and contingent conditions. Therefore, Project Pajarito will cause power to flow into South Coors Substation. Substation load may be exceeded causing power to flow into the transmission system. No transmission related issues are anticipated.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. The metering equipment will be capable of capturing the PV system's generation profile data in the time intervals specified in the interconnection agreement. Also located at the same point will be communication equipment that will allow PNM to access and download data from the meters into the PNM monitoring system in real time. The meter information will be used to monitor the PV system's output level (KW and KWH) and operational status instantaneously, historically, and for billing purposes.

Communications Cost Estimate:

ONE-TIME Equipment Cost	$XXXXX
One-Time Labor Cost	$XXXXX
MONTHLY Recurring O&M	$XXXXX

Breakdown of the ONE-TIME Equipment Cost:

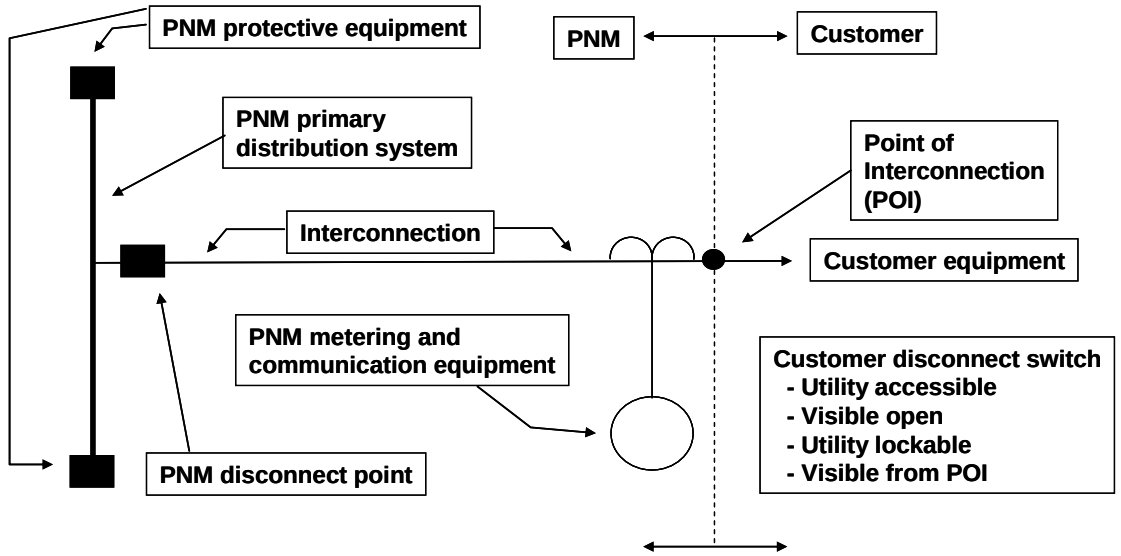
Satellite or TELCO PRIMARY Installation	$XXXXX
Microwave or other backup Install	$XXXXX
Channel Bank Equipment	$XXXXX

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 – Typical Project Interconnection

Typical connection of a Photovoltaic system to the PNM distribution system



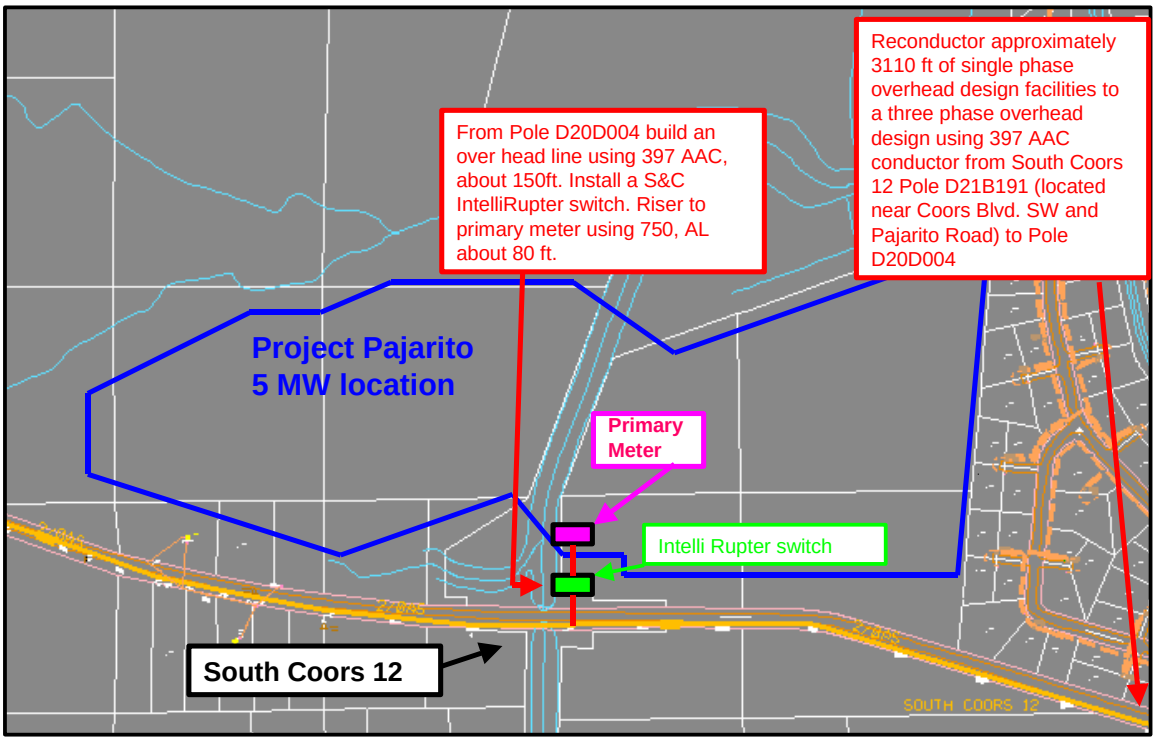
The PNM disconnect point will consist of a SCADA controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project Pajarito to the PNM distribution system, system upgrades and a line extension are required. The interconnection consists of:

- Reconductor approximately 3110 ft of single phase overhead design facilities to a three phase overhead design using 397 AAC conductor from South Coors 12 Pole D21B191 (located near Coors Blvd. SW and Pajarito Road) to Pole D20D004 (See Figure 4)
- Build approximately 150ft of new 397 AAC overhead circuit from Pole D20D004 to the PV site location (See Figure 4)
- Install one S&C IntelliRupter switch (See Figure 4)
- Riser to primary meter, about 80ft, using 750 AL (See Figure 4)

Figure 4 – System upgrade for Project Pajarito



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 7.

Table 7 ***- Project Pajarito Interconnection Cost***

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRuptor)	$XXXXX	~ 16 week lead time ~ 3 days to build
Overhead line extension	$XXXXX	~ 16 week lead time ~ 2 weeks to build
Primary metering	$XXXXX	~ 3 week lead time ~ 4 days to build
Right of Way	$XXXXX	
Communication	$XXXXX	
Communication monthly O&M	$XXXXX	
TOTAL	$XXXXX **Plus monthly O&M of** $XXXXX	**5-6 months for lead time and final build out.**

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple landowners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Distribution Planning performed a screening analysis of Project Pajarito 5 MVA PV system operating at 100% (unity) power factor and determined there was an adverse impact on the PNM electric distribution system when Sewer Plant Feeder 14 is used to serve the area. The analysis concluded that Project operation at 97.5% power factor mitigated the adverse impact allowing the electric distribution system to operate within the PNM established criteria. This Study recommends operating procedures be developed to mitigate over voltage concerns as noted in this study that require Project Pajarito be operated at a fixed 97.5% power factor when served from Sewer Plant Feeder 14. The Project will be injecting 4,875 KW into the electric distribution system and absorbing 1,111 KVAR from the electric distribution system at the POI.

Analysis shows voltages will remain within the PNM criteria of ANSI C84.1 for all normal conditions and with the Project operating at a 97.5% power factor when served from Sewer Plant Feeder 14. There are two remotely controlled capacitor banks on the feeder associated with Project Pajarito. These capacitors are normally de-energized and Project Pajarito requires them to be energized when operating at maximum contingent conditions. The automatic control of voltage by the substation LTC will not cause the LTC to operate, but this does not have an adverse effect. The Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductor ratings to be exceeded. The Project contribution to fault current does not adversely impact the protection coordination on South Coors Feeder 11, 12, and 14, South Coors Substation, Sewer Plant Feeder 14, or Sewer Plant Substation. Finally, analysis shows that Project Pajarito output variation will not cause voltage flicker issues on the electric distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Pajarito and has determined that there are no adverse impacts associated with a 5,000 KVA AC source operating, connected to South Coors Feeder 12 for the normal system configuration or to Sewer Plant Feeder 14 for the contingent system configuration when operating at a 97.5% power factor.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on South Coors Substation is maintained within established PNM voltage, equipment and fault protection criteria.

Public Service Company of New Mexico
Generation Planning and Development

Reeves 3,000 KW PV Generation Project

Small Generator Interconnection System Impact Study

(SGI-PNM-2010-06)

September 2010

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for Public Service Company of New Mexico Generation Planning and Development by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

Public Service Company of New Mexico Generation Planning and Development Department submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 3,000 KW AC to the Public Service Company of New Mexico ("PNM") distribution primary system. The request is identified as Project Reeves ("Project Reeves") and would be connected to Reeves Feeder 11. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures ("SGIP") for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study was performed by PNM Transmission/Distribution Planning and Contracts ("Distribution Planning").

The estimated cost of connecting Project Reeves to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ 52,800	13 weeks
Interconnection**	$ 40,700	21 weeks
PNM metering	$ 19,400	13 weeks
Communication	$ 29,000	
Protection***	$ 0	
TOTAL	**$ 141,900**	21 weeks (5-6 months)

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

The application notes the use of a Sunny Central ("SC") SMA 500CP inverter. The technical data notes for the SC SMA 500SC inverter were used to prepare this report. The data shows this inverter is presently not certified as UL 1741 complaint. The SC SMA 500SC inverter will have a 1,000V DC rating and is designed to meet UL 1741 compliance standards. Since UL

testing is limited to 600V systems the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer technical data the inverter is capable of maintaining a unity power factor and this study assumed that the facility maintained unity power factor. Distribution Planning recommends the use of an inverter listed as UL 1741 complaint to insure, among other concerns, that the inverter will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other requirements as indicated in the SGIP application, Attachment 3. A complete field checkout of non-complaint equipment at the proposed facility is recommended before the facility can be considered certified for interconnection operation.

This System Impact Study ("Study") evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the PNM distribution primary system. The photovoltaic generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Reeves does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Reeves Feeder 11 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds were found to not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not require the Reeves Feeder 11, Reeves Substation, Wayne Feeder 14 or Wayne Substation protection scheme be modified.
7. Project output will not cause a flow of electricity from the distribution system through the Reeves or Wayne Unit 1 Substation transformer. There is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Reeves and has determined that there are no adverse impacts associated with a 3,000

KW AC source connected to Reeves Feeder 11 for the normal system configuration or to Wayne Feeder 14 for the contingent system configuration.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Reeves Substation is maintained within established PNM voltage, equipment and fault protection criteria.

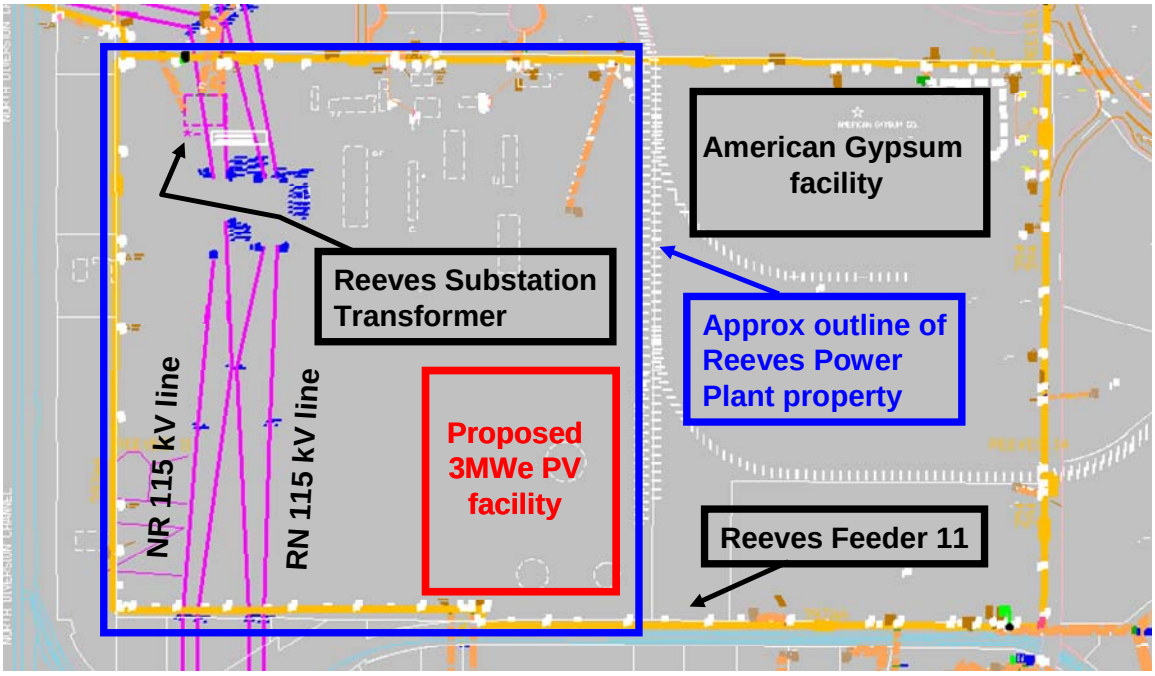
1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a photovoltaic ("PV") electric generation source connected to the PNM distribution primary system identified as Project Reeves. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage and current produced by the PV equipment to AC voltage and current. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Reeves proposes to connect a 3,000 KW AC PV facility to Reeves Substation Feeder 11 in Albuquerque, NM. The Project will be located on the east side of the Reeves Power Plant property in Albuquerque as shown in Figure 1. The circuit distance from Reeves Substation to the Project Reeves point of interconnection ("POI") is about 3,775 ft or 0.72 miles.

Figure 1 ***– Project Reeves location***



3.0 SYSTEM CONFIGURATION

Project Reeves is connected to Reeves Feeder 11 served from Reeves Substation. The Project is normally served from Reeves Feeder 11 with contingency backup provided by Wayne Feeder 14. Table 1 shows the rating of Reeves and Wayne Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Reeves	22.4	22.10	24.50	115-12.47
Wayne One	33.6	35.50	38.50	115-12.47

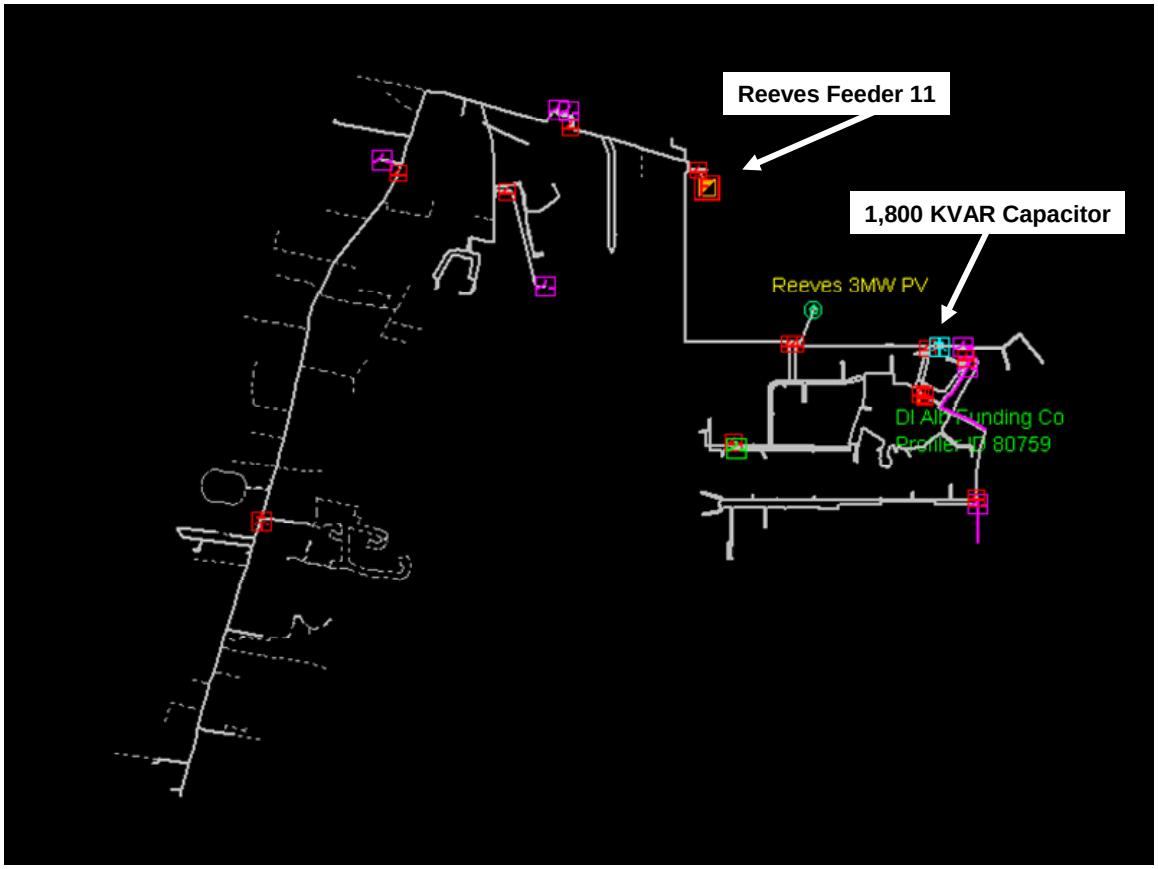
Table 2 shows the non-coincident peak 2009 peak summer loads for Reeves and Wayne Substation and feeders.

***Table 2* - July 2009 Non-coincident Peak Loads**

Feeder	July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Reeves				
Reeves 11	5,403	-232	5,408	-99.9
Reeves 12	0	0	0	
Reeves 13	6,289	1,013	6,370	98.7
Reeves 14	6,078	549	6,103	99.6
Reeves Sub	17,485	1,161	17,523	99.8
Wayne One				
Wayne 11	1,178	463	1,266	93.1
Wayne 12	4,397	1,601	4,679	94.0
Wayne 13	5,595	-519	5,619	-99.6
Wayne 14	3,648	-792	3,733	-97.7
Wayne Sub	13,305	40	13,305	100.0

Figure 2 is a picture of the distribution feeder model used in the GL Synergee analysis program.

Figure 2 ***- Synergee model of Reeves Feeder 11***



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on Reeves Feeder 11 and Wayne 14 are shown in Table 3:

Table 3 *- Max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Reeves 11								
July 14, 2009	2 PM	5,403	-232	5,408	-99.9	252	244	241
May 24, 2009	7 AM	1,351	-180	1,363	-99.1	63	60	61
Wayne 14								
Dec 7, 2009	11 AM	3,880	734	3,949	98.3	203	169	162
May 24, 2009	7 AM	968	-184	985	-98.2	54	41	41

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

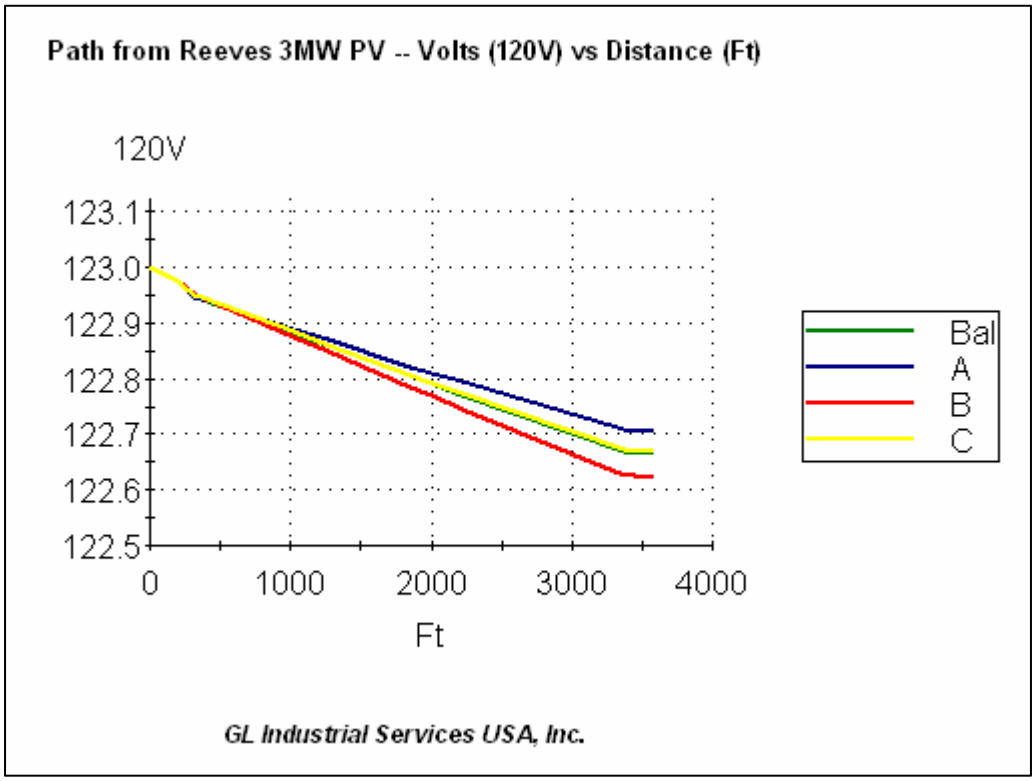
4.1 Voltage impacts on the transmission system

The transmission system was modeled for minimum daylight hours load. No transmission voltage issues are anticipated associated with Project Reeves at maximum output.

4.2 Voltage impacts for maximum daylight hours load

The Reeves Feeder 11 voltage for the feeder maximum daylight hours load for 2009 with and without Project Reeves, per the Synergee model, are shown in Graphs 1 and 2.

Graph 1 - Reeves Feeder 11 voltage drop from Reeves Substation to Project Reeves POI for daylight hours maximum load on July 14, 2009. Project Reeves is OFF.

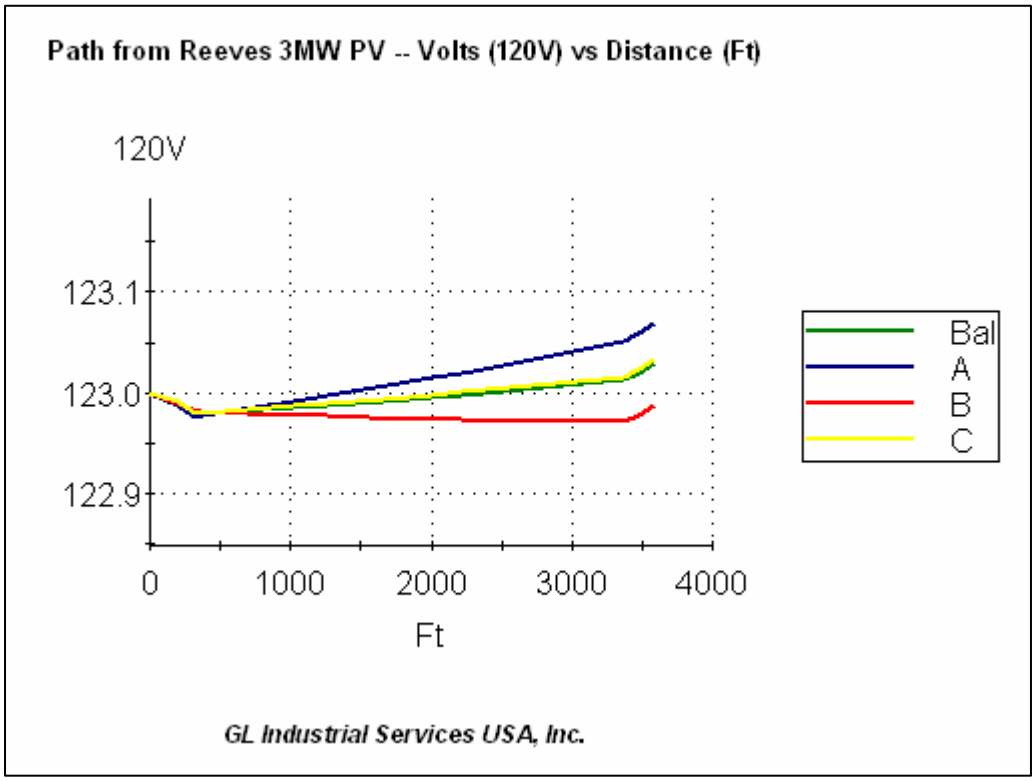


The model voltages at the point of interconnection are:

Phase A – 122.7 volts Phase B – 122.6 volts Phase C – 122.7 volts Balanced – 122.7 volts

The voltages on Reeves Feeder 11 prior to the installation of Project Reeves are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 being energized.

Graph 2 - Reeves Feeder 11 voltage drop from Reeves Substation to Project Reeves POI for daylight hours maximum load on July 14, 2009. Project Reeves is ON.



The model voltages at the point of interconnection are:

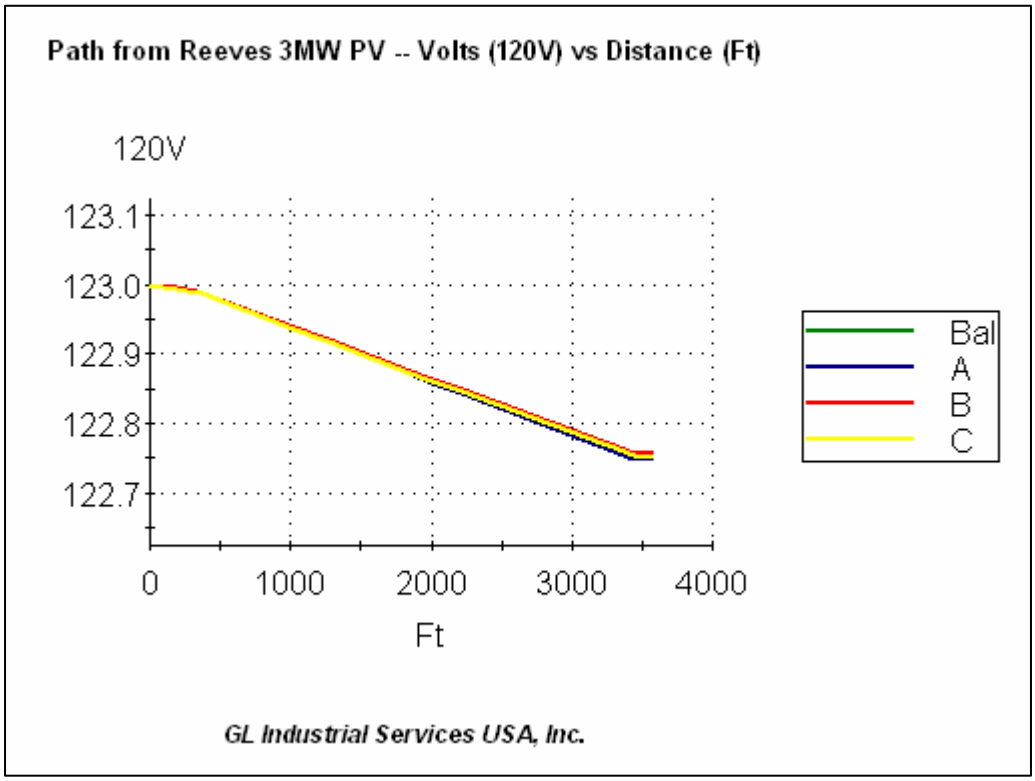
Phase A – 123.1 volts Phase B – 123.0 volts Phase C – 123.0 volts Balanced – 123.0 volts

The voltages on Reeves Feeder 11 after the installation of Project Reeves increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 being energized.

4.3 Voltage impacts for minimum daylight hours load

The Reeves Feeder 11 voltage for the feeder minimum daylight hours load for 2009 with and without Project Reeves, per the Synergee model, are shown in Graphs 3 and 4.

Graph 3 – Reeves Feeder 11 voltage drop from Reeves Substation to Project Reeves POI for daylight hours minimum load on May 24, 2009. Project Reeves is OFF.

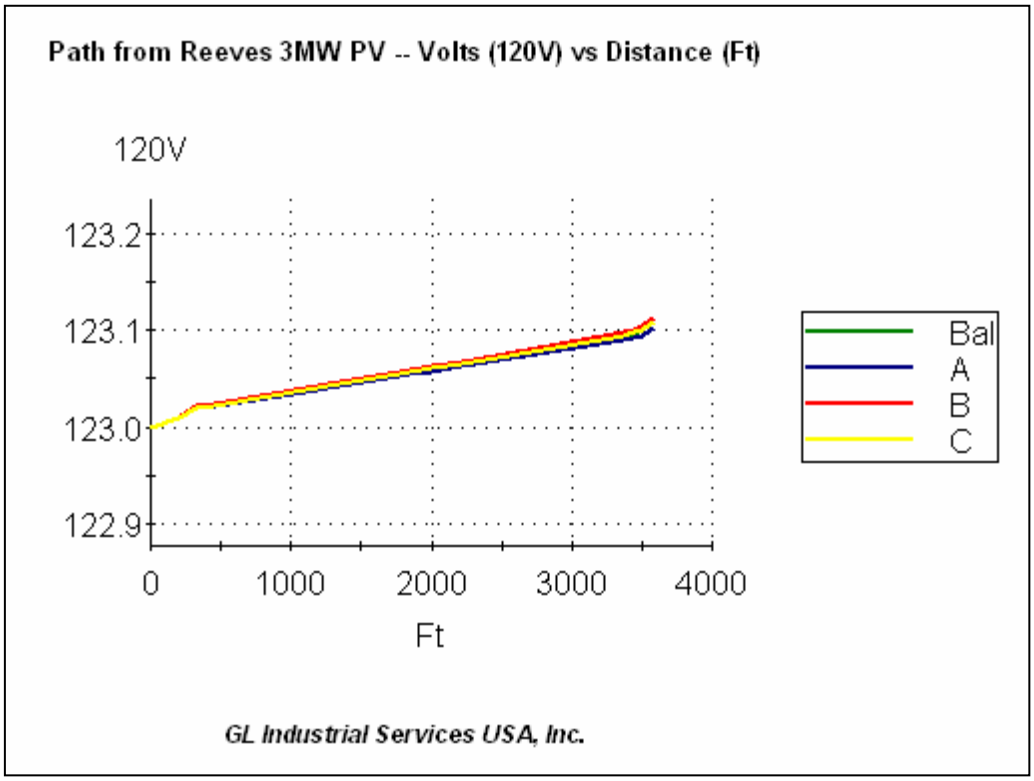


The model voltages at the point of interconnection are:

Phase A – 122.7 volts Phase B – 122.8 volts Phase C – 122.8 volts Balanced – 122.8 volts

The voltages on Reeves Feeder 11 prior to the installation of Project Reeves are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 being de-energized.

Graph 4 - Reeves Feeder 11 voltage drop from Reeves Substation to Project Reeves POI for daylight hours minimum load on May 24, 2009. Project Reeves is ON.



The model voltages at the point of interconnection are:

Phase A – 123.1 volts Phase B – 123.1 volts Phase C – 123.1 volts Balanced – 123.1 volts

The voltages on Reeves Feeder 11 after the installation of Project Reeves increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 being de-energized.

In conclusion, Project Reeves output does cause the voltage on Reeves Feeder 11 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

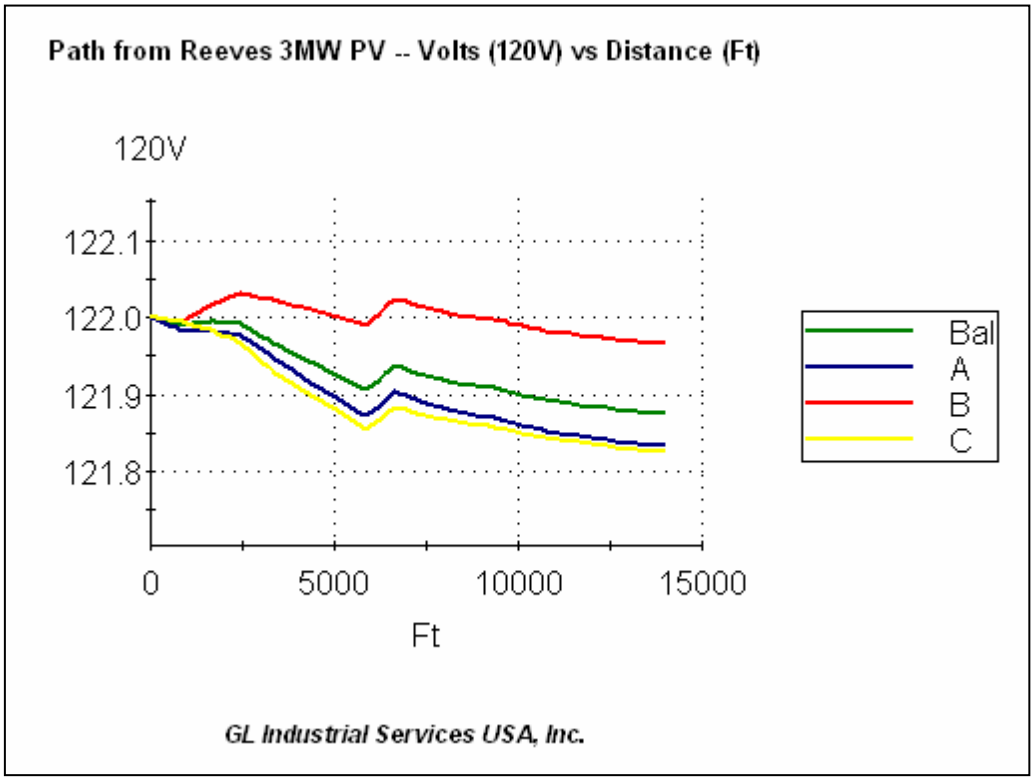
4.4 Voltage impacts during an outage of Reeves Substation

Wayne Feeder 14 backs up the portion of Reeves 11 that serves Project Reeves when Reeves Substation is out-of-service due to maintenance or equipment failure. The maximum and minimum loading on Wayne 14 for the hours of 7AM to 7PM is shown in Table 3. For the condition of Reeves Substation out-of-service, 35% of Reeves 11 is transferred to Wayne 14.

4.4.1 Voltage impacts for minimum daylight hours load during an outage of Reeves Substation

The Wayne Feeder 14 voltage for minimum daylight hours load for 2009 with and without Project Reeves, per the Synergee model, are shown in Graphs 5 and 6.

Graph 5 - Wayne Feeder 14 voltage drop from Wayne Substation to Project Reeves POI for daylight hours minimum load. Project Reeves is OFF.

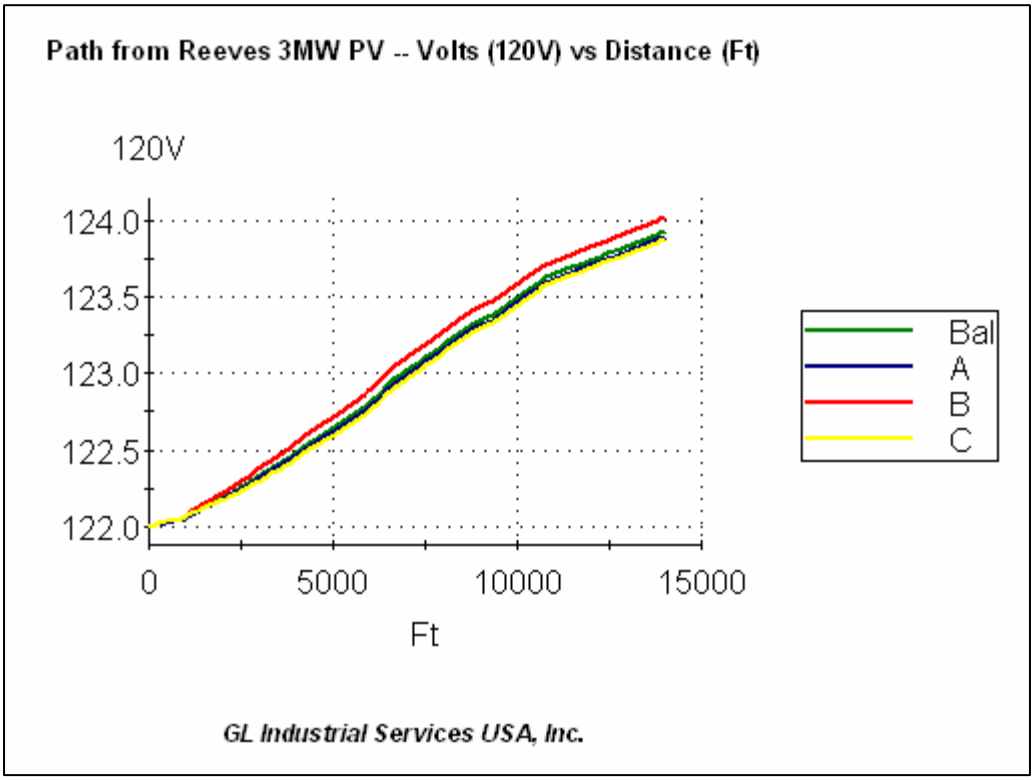


The model voltages at the point of interconnection are:

Phase A – 121.8 volts Phase B – 122.0 volts Phase C – 121.8 volts Balanced – 121.9 volts

The voltages on Wayne Feeder 14 prior to the installation of Project Reeves are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 and the 1,800 KVAR switched capacitor on Wayne 14 being de-energized.

Graph 6 – Wayne Feeder 14 voltage drop from Wayne Substation to Project Reeves POI for daylight hours minimum load. Project Reeves is ON.



The model voltages at the point of interconnection are:

Phase A – 123.9volts Phase B – 124.0 volts Phase C – 123.9 volts Balanced – 123.9 volts

The voltages on Wayne Feeder 14 after the installation of Project Reeves increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is

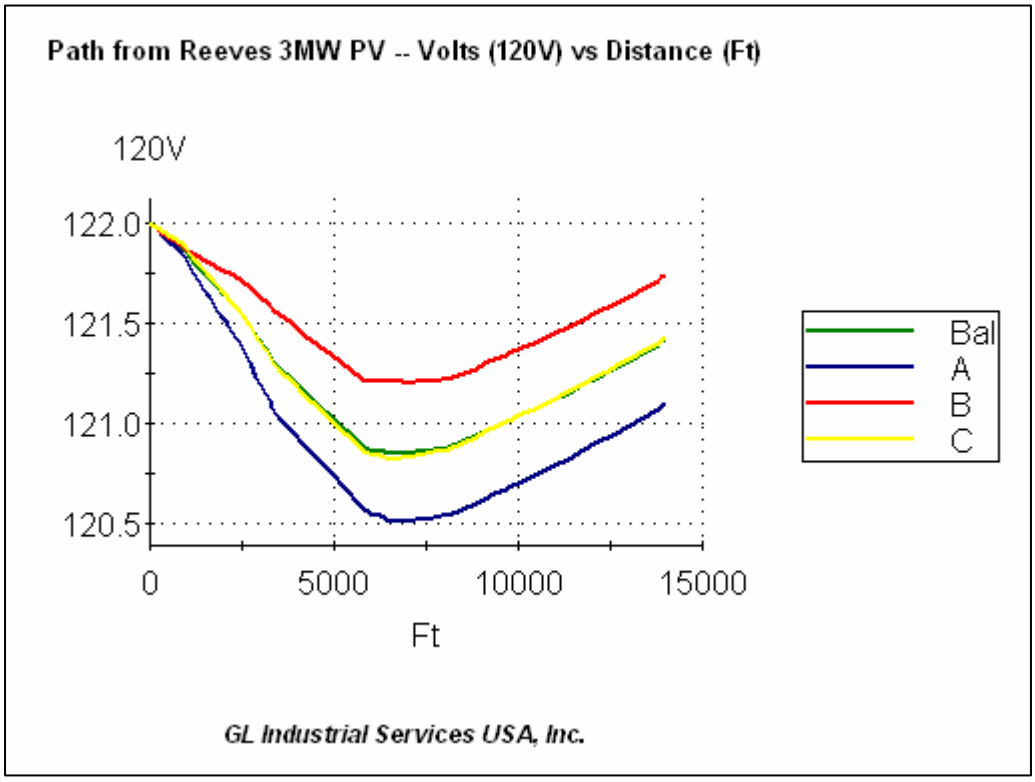
based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 and the 1,800 KVAR switched capacitor on Wayne Feeder 14 being de-energized.

In conclusion, Project Reeves output does cause the voltage on Wayne Feeder 14 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

4.4.2 Voltage impacts for maximum daylight hours load during an outage of Reeves Substation

The Wayne Feeder 14 voltage for maximum daylight hours load for 2009 with and without Project Reeves, per the Synergee model, are shown in Graphs 7 and 8.

Graph 7 – Wayne Feeder 14 voltage drop from Wayne Substation to Project Reeves POI for daylight hours maximum load. Project Reeves is OFF.

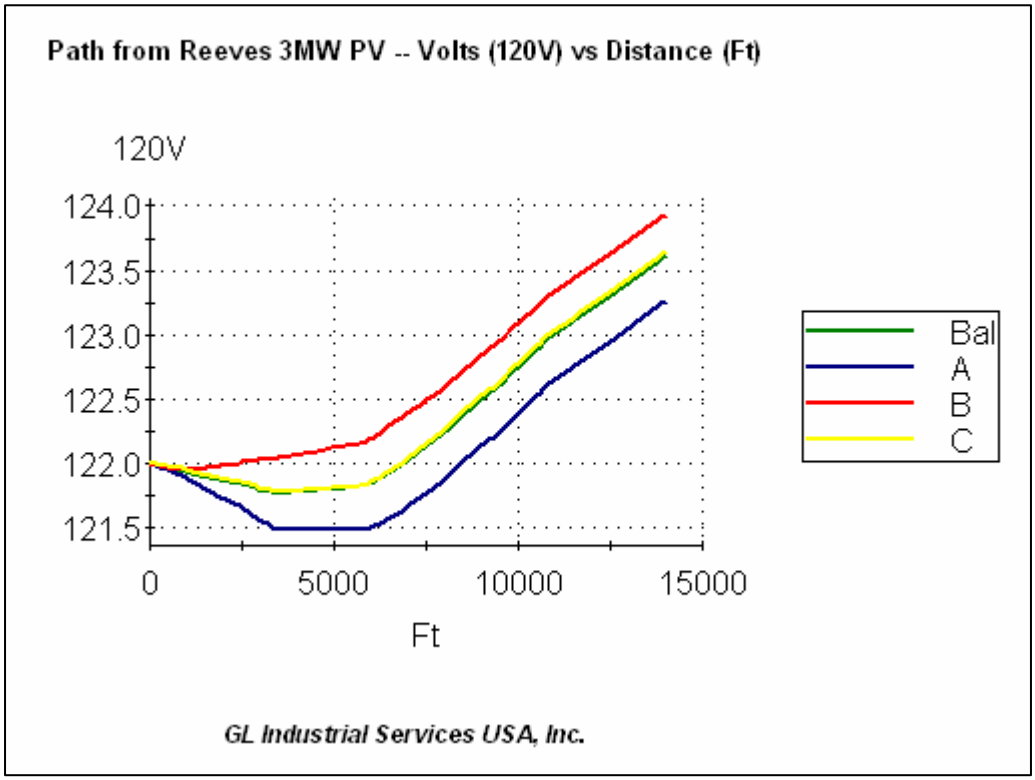


The model voltages at the point of interconnection are:

Phase A – 121.1 volts Phase B – 121.7 volts Phase C – 121.4 volts Balanced – 121.4 volts

The voltages on Wayne Feeder 14 prior to the installation of Project Reeves are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. The voltage plot profile is the result of the capacitor on Reeves 11. This model is based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 and the 1,800 KVAR switched capacitor on Wayne Feeder 14 being energized.

Graph 8 – Wayne Feeder 14 voltage drop from Wayne Substation to Project Reeves POI for daylight hours maximum load. Project Reeves is ON.



The model voltages at the point of interconnection are:

Phase A – 123.3 volts Phase B – 123.9 volts Phase C – 123.6 volts Balanced – 123.6 volts

The voltages on Wayne Feeder 14 after the installation of Project Reeves increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor bank on Reeves Feeder 11 and the 1,800 KVAR switched capacitor on Wayne Feeder 14 being energized.

In conclusion, Project Reeves output does cause the voltage on Wayne Feeder 14 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Reeves Feeder 11 does not have a voltage regulator installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

Synergee modeling showed that the voltage variance at the substation due to a 3,000 KW source on the feeder would be about 0.1 volts for high or low load periods. This voltage variance will be insufficient to cause the substation LTC to operate for high or low load on the feeder.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a

distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Reeves POI is shown in Section 4.0. Table 4 summarizes the balanced voltage and the calculated voltage flicker. Table 5 is based on the GE flicker graph.

***Table 4* - Voltage flicker on Reeves Feeder 11 due to Project Reeves**

	POI Voltage Reeves Feeder 11 Loading	
	Minimum	**Maximum**
Without Project	122.8	122.7
With Project	123.1	1223.0
% Voltage Flicker	**0.24**	**0.24**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Project output will vary rather than spike between on and off thus Table 4 results are worst case. Cloud movement is slow thus voltage flicker will be less than the results shown in Table 4. Per the GE Flicker Graph, distribution voltage flicker shown in Table 4 is too small to apply to either the visibility or irritation curves. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Reeves POI to the substation were reviewed using the Synergee feeder model with and without Project Reeves maximum output of 3,000 KW AC.

There were no conductor loading problems from the POI to the substation on Reeves Feeder 11 for the normal system configuration or on Wayne Feeder 14 for the contingent system configuration with and without Project Reeves during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source (watts only, no vars) for the distribution system. When the inverter is operating the power factor of the distribution feeder will be affected.

RCCS adjusts the power factor of individual feeders. Reeves Feeder 11 has one 1,800 KVAR RCCS controlled capacitor banks. The July 2009 peak load on the feeder was 5,403 KW – j 232 KVAR or 5,408 KVA at a 99.9% leading power factor (i.e. 100.1% power factor). The switched capacitor was energized. Project Reeves at a 3,000 KW AC output would change the apparent feeder loading to 2,403 KW – j 232 KVAR or 2,414 KVA at a 99.5% leading power factor. This power factor value change is minimal. The RCCS program will not adjust the feeder power factor and the 1,800 KVAR capacitor will not be de-energized by the RCCS program.

9.0 PROTECTION

9.1 Normal Configuration – Service from Reeves Feeder 11

Reeves Substation feeder 11 is protected by a 1200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one

Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, CA differential relays. The Reeves Project PV system will be connected to the system approximately 0.68 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 260 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miss-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 3 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miss-coordination issues on the feeder.

Project Reeves does not require any system protection improvements to be made to the Reeves Substation feeder 11 under normal configuration.

9.2 Contingency Configuration – Reeves Feeder 11 picks up Mission Feeder 24 for an outage of Hawkins Substation

Fault analysis of the system was conducted with Reeves feeder 11 in a contingency condition picking up load from Mission feeder 24 to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 260 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miss-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 3 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miss-coordination issues on the feeder.

Project Reeves does not require any system protection improvements to be made to the Reeves Substation feeder 11 under normal feeder as a backup feeder for Mission feeder 24.

9.3 Contingency Configuration – Reeves Feeder 11 picks up Los Angeles Feeders 11 & 13 for an outage of Los Angeles Substation

Fault analysis of the system was conducted with Reeves feeder 11 in a contingency condition picking up load from Los Angeles feeder 11 and 13 to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 260 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miss-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 3 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miss-coordination issues on the feeder.

Project Reeves does not require any system protection improvements to be made to the Reeves Substation feeder 11 under normal feeder as a backup feeder for Los Angeles feeders 11 and 13.

9.4 Contingency Configuration – Reeves Feeder 11 picks up Wayne Feeder 14 for an outage of Wayne Substation

Fault analysis of the system was conducted with Reeves feeder 11 in a contingency condition picking up load from Wayne feeder 14 to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 260 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miss-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 3 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miss-coordination issues on the feeder.

Project Reeves does not require any system protection improvements to be made to the Reeves Substation feeder 11 under normal feeder as a backup feeder for Wayne feeder 14.

9.5 Contingency Configuration – Wayne Feeder 14 picks up Reeves Feeder 11 for an outage of Reeves Substation

Contingency Configuration:

Wayne Substation feeder 14 is protected by a 1200 amp breaker in metal clad switchgear with an ABB, DPU2000R extremely inverse phase overcurrent relay, a very inverse ground overcurrent relay and reclosing relay. The switchgear bus and feeder backup protection is an ABB, DPU2000R extremely inverse phase relay and an ABB, DPU2000R extremely inverse ground relay. The transformer protection is an ABB, TPU2000R differential relay. The Reeves Project PV system will be connected to the system approximately 2.65 miles from the Wayne substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 260 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miss-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 3MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions

from the PV system do not create any feeder breaker protection miss-coordination issues on the feeder.

The Reeves Project does not require any system protection improvements to be made under contingency configuration to the Wayne Substation feeder 14.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Reeves output exceeds the minimum load on Reeves Feeder 11 during daylight hours. Therefore, Project Reeves may cause a flow of power into Reeves Substation. Substation minimum load will not be exceeded; thus, no power will flow through the substation transformer to the transmission system. No adverse effects were identified.

11.0 METERING and COMMUNICATION

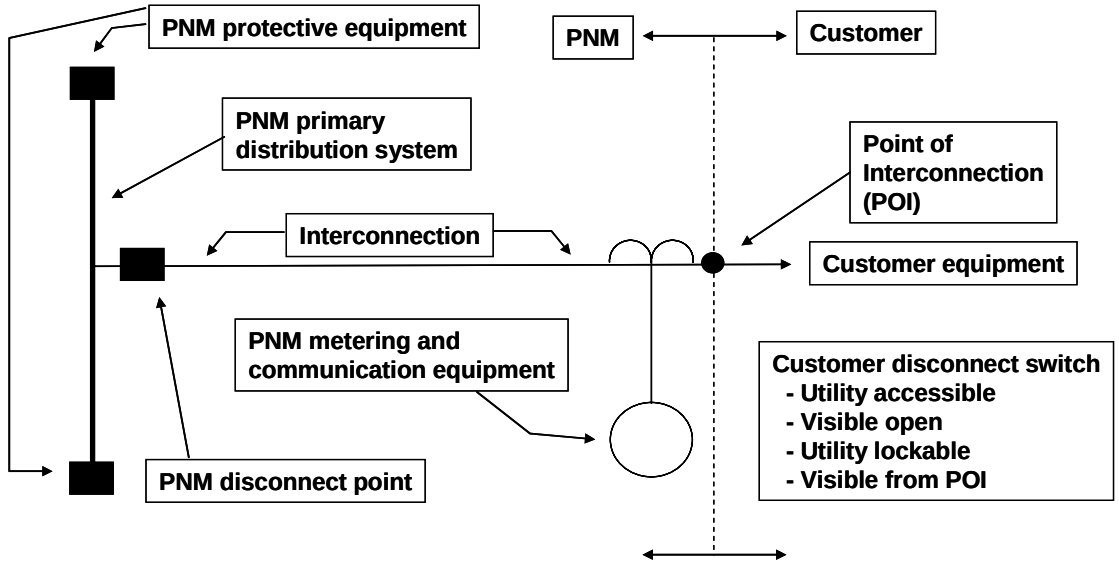
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 5.

Table 5 ***- Project Reeves Interconnection Cost***

	ESTIMATED COSTS 2010$
PNM disconnect point*	$ 52,800
Interconnection**	$ 40,700
PNM metering	$ 19,400
Communication	$ 29,000
Protection***	$ 0
TOTAL	**$ 141,900**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction

should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Project Reeves does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Reeves Feeder 11. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC may cause the LTC to operate but this is not considered an adverse issue. The Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductors ratings to be exceeded. The Project contribution to fault current does not adversely impact the protection coordination on Reeves Feeder 11, Reeves Substation, Wayne Feeder 14 or Wayne Substation. Finally, analysis shows that Project Reeves output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Reeves and has determined that there are no adverse impacts associated with a 3,000 KW AC source connected to Reeves Feeder 11 for the normal system configuration or to Wayne Feeder 14 for the contingent system configuration.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Reeves Substation is maintained within established PNM voltage, equipment and fault protection criteria.

Public Service Company of New Mexico
Generation Planning and Development

Project Tome 6,000 KW PV Generation Project

Small Generator Interconnection Feasibility Study

(SGI-PNM-2010-07)

September 2010

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for Public Service Company of New Mexico Generation Planning and Development Department by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

Public Service Company of New Mexico Generation Planning and Development submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system with a nominal rating of 6,000 KW AC to the Public Service of New Mexico ("PNM") distribution primary system. The request is identified as Project Tome and would be connected to Manzano Feeder 13. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures ("SGIP") for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study was performed by Public Service Company of New Mexico Transmission/distribution Planning and Contracts ("Distribution Planning").

The estimated cost of connecting Project Tome to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRupter)	$ 51,500	~16 week lead time ~3 Days to build
Interconnection (Line Construction)	$ 340,300	~16 week lead time ~8-10 weeks to build
PNM Primary metering	$ 24,100	~3 week lead time ~ 4 days to build
TOTAL	**$ 415,900**	**6-7 months for lead time and final build out.**

The technical data notes for the SMA SC 500SC inverter were used to prepare this report. The data shows that this inverter is presently not a certified UL 1741 compliant inverter. The SMA SC 500SC inverter will have a 1000V DC rating and is designed to meet UL 1741 compliance standards. Since UL testing is limited to 600V systems the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer technical data notes the inverter is capable of maintaining a unity power factor but also has the capability to control the reactive power to support voltage control. Due to voltage control issues identified in this report, voltage

regulation will be required, which precludes the use of a UL 1741 compliant inverter. Distribution Planning recommends the use of a UL listed 1741 compliant inverter to insure that, among other concerns, that the unit will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other various requirements as called out in the SGIP application, Attachment 3. A complete field checkout of non-complaint equipment at the proposed facility is recommended before the facility can be considered certified for interconnection operation.

This System Impact Study ("Study") evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic ("PV") generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Tome does have an adverse impact on the PNM distribution system when operating at 100% power factor, and the following results are based on the inverter utilizing a power factor fixed at 98.5% lagging. Project Tome would still be injecting 5,910 KW which does not have an adverse impact on the system. Approximately 1,035 KVAR would need to be absorbed/imported by the project.

The Project location will result in an interconnection with Manzano Feeder 13 and the analysis results with the inverter operating at 98.5% power factor lagging were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds are not anticipated to cause voltage flicker problems.
4. Project output did cause conductor ratings to be exceeded, a system upgrade to reconductor approximately 1,000 ft. of 2 ACSR is included in the interconnection cost.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not adversely impact the protection coordination on the Manzano substation or Manzano Feeder 13 for normal or contingent

configurations, however the available fault current from the PV system may be higher than the ground pickup on the feeder relay. Additionally, the Project contribution to fault current does not adversely impact the Tome substation or Tome Feeder 12 protection scheme for contingent configuration.

7. Project output will cause a flow of electricity from the distribution system through the substation transformer, but this is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Tome and has determined that there are no adverse impacts associated with a 6,000 KVA AC source connected to Manzano Substation with a dedicated distribution primary source of Manzano Feeder 13 when operating at a fixed, lagging 98.5% power factor (5,910 KW + 1,035 KVAR).

Distribution Planning has identified that system upgrades are required to ensure that electric service to all customers on Manzano Substation is maintained within established PNM voltage, equipment and fault protection criteria.

1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a photovoltaic ("PV") electric generation source connected to the distribution primary system identified as Project Tome. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

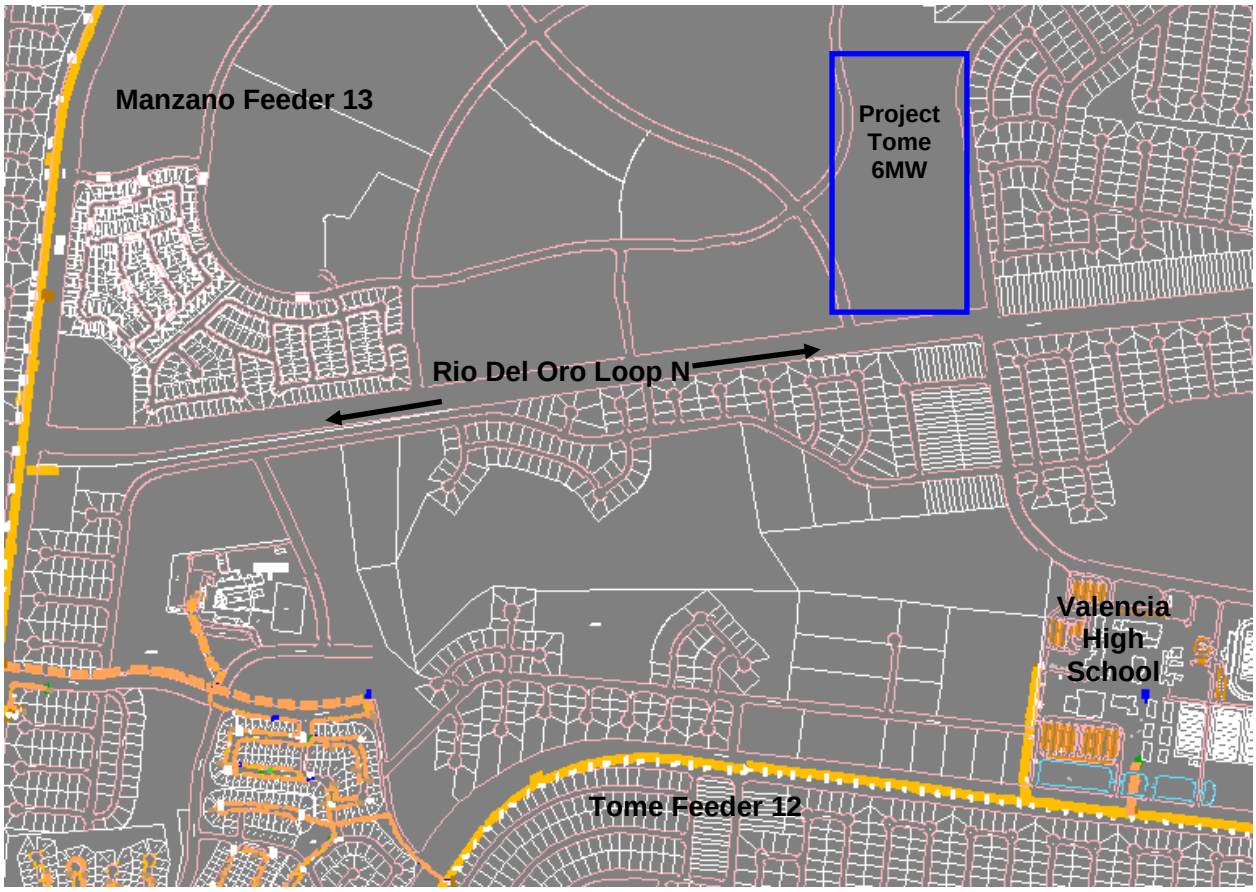
2.0 PROJECT LOCATION

Project Tome is located on the northwest corner of Rio Del Oro Loop N. and Bonita Vista Blvd. in Los Lunas, NM as shown in Figure 1.

***Figure 1* – Project Tome Location**

The project location can be served from either Tome Feeder 12 or Manzano Feeder 13 as shown in Figure 2. The project proposes to connect a 6,000 KW AC PV facility to Tome Feeder 12.

Figure 2 ***– Project Tome Proximity to Tome and Manzano Feeders***



Initial studies connecting to Tome Feeder 12 resulted in voltages above 126 V, which is above the ANSI C84.1 Range A upper limit. Initial studies indicated a connection to Manzano Feeder 13 resulted in voltages within ANSI limits. A system upgrade results in the point of interconnection ("POI") for Project Tome to be on Tome Feeder 12 which requires transferring a portion of Tome Feeder 12 to Manzano Feeder 13. This study evaluates Project Tome connecting to Manzano Feeder 13. The circuit distance from Manzano Substation to the Project Tome POI is about 32,159 ft. or 6.09 miles.

3.0 SYSTEM CONFIGURATION

Project Tome is a large PV source and is proposed to be connected to Manzano Feeder 13 served from Manzano Substation. Table 1 shows the rating of Manzano Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Manzano	14.0	15.45	16.80	115-12.47

Table 2 shows the 2009 peak summer loads for Manzano Substation and feeders, this data is not coincident with PNM's 2009 system wide peak demand timeframe.

***Table 2* - July 2009 Non-coincident Peak Loads**

Feeder	July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Manzano 11	3,229	285	3,241	99.6
Manzano 12	570	243	620	91.9
Manzano 13	5,688	1,002	5,775	98.5
Manzano Sub	9,180	1,477	9,298	98.7

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Manzano Feeder 13 are shown in Table 3:

Table 3 *- Manzano Feeder 13 max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 13,2009	6 PM	5,688	1,002	5,776	98.5	271	279	238
May 24, 2009	7 AM	1,572	-165	1,581	-99.4	103	104	101

The results from the Synergee model for the maximum and minimum daylight hours loading on Manzano Feeder 13 after a load transfer from Tome Feeder 12 to Manzano Feeder 13 are shown in Table 4.

Table 4 *- Manzano Feeder 13 max/min Daylight Hours Load After Load Transfer*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 13,2009	6 PM	6,348	158	6,349	99.9	296	304	268
May 24, 2009	7 AM	2,466	-151	2,471	-99.8	112	114	112

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Tome at maximum output exceeds the load on Manzano Feeder 13 at minimum load timeframes. Therefore, Project Tome will cause a flow of power into Manzano Substation. Table 5 shows the maximum and minimum load on the Manzano Substation transformer.

Table 5 ***- Manzano Substation max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 20,2009	5:30 PM	9,180	1,477	9,298	98.7	453	445	373
May 24, 2009	7 AM	2,627	-1,572	3.061	-85.8	163	146	148

The minimum load on the Manzano Substation transformer, as shown in Table 5, is less than the rated output of Project Tome. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system.

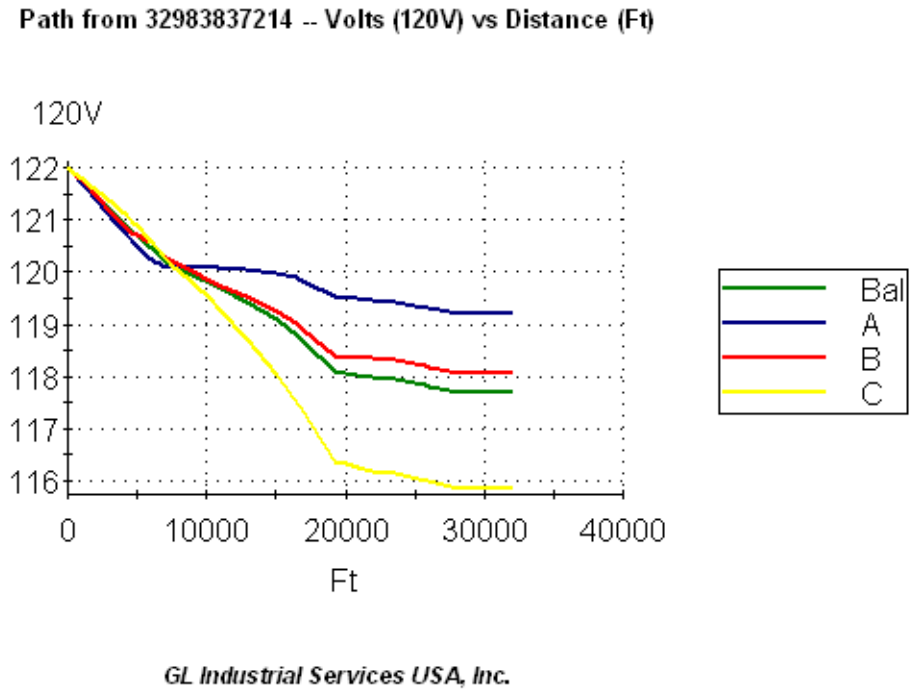
4.1 Voltage impacts on the transmission system

Although the minimum load on the Manzano Substation transformer is less than the rated output of the project, the difference is less than 5 MW, therefore no transmission related issues are anticipated to be associated with Project Tome.

4.2 Voltage impacts for maximum daylight hours load for normal configuration

The Manzano Feeder 13 voltage for the feeder daylight hours maximum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 1 and 2. Larger customer loads on the feeder, including UNM-Valencia Campus and Valencia High School, were modeled using actual load values from the daylight hours maximum date and time.

Graph 1 - Manzano Feeder 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is OFF.

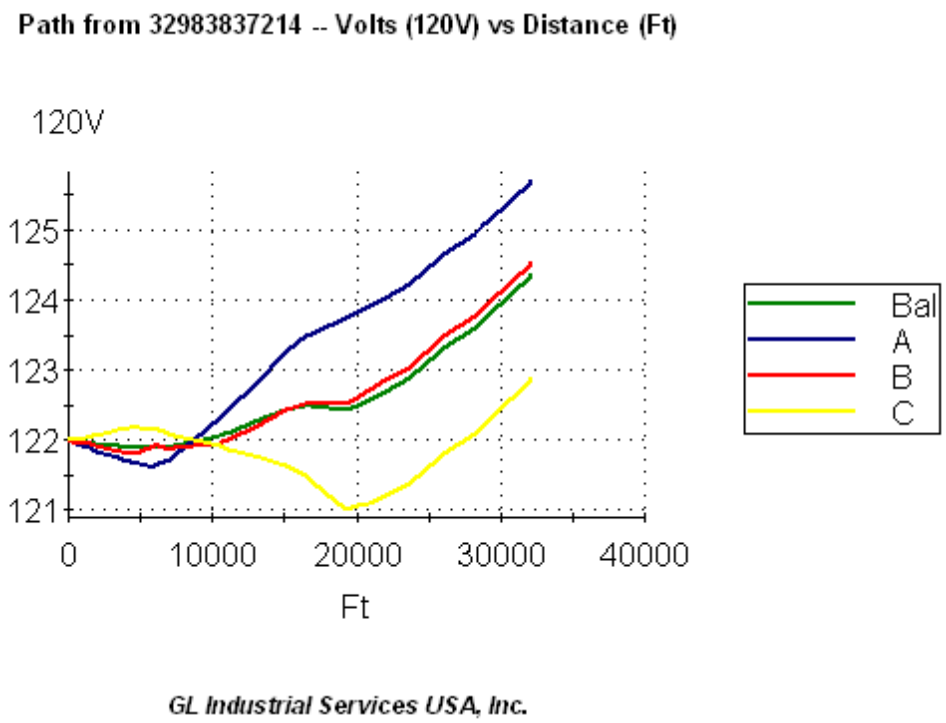


The model voltages at the point of interconnection are:

Phase A – 119.2 volts Phase B – 118.1 volts Phase C – 115.9 volts Balanced – 117.7 volts

The voltages on Manzano Feeder 13 prior to the installation of Project Tome are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 - Manzano Feeder 13 voltage drop from Manzano Substation to Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is ON, 100% power factor.



The model voltages at the point of interconnection are:

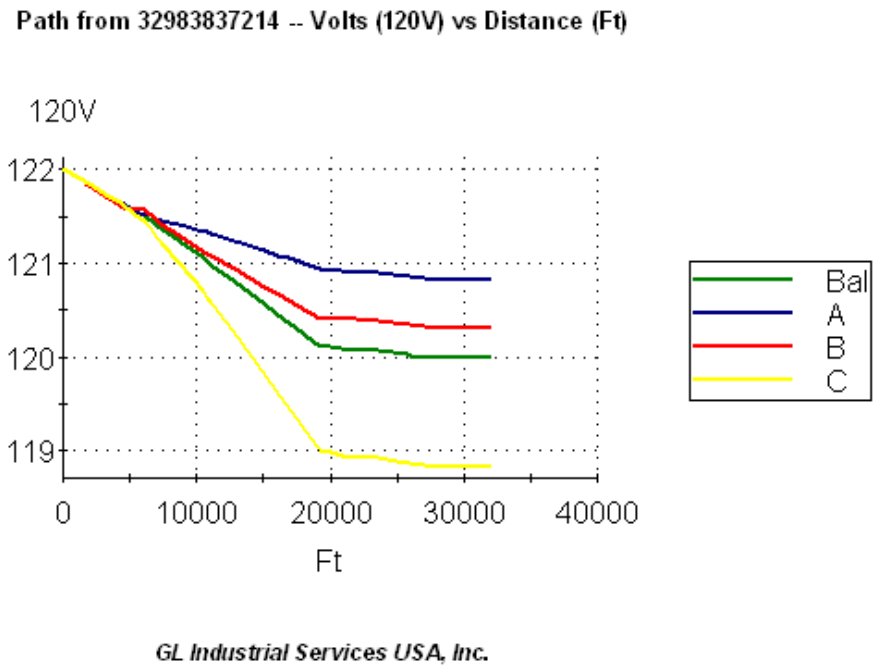
Phase A – 125.7 volts Phase B – 124.5 volts Phase C – 122.9 volts Balanced – 124.4 volts

The voltages increase on Manzano Feeder 13 after the installation of Project Tome but are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.3 Voltage impacts for minimum daylight hours load for normal configuration

The Manzano Feeder 13 voltage for the feeder daylight hours minimum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 3, 4 and 5. Larger customer loads on the feeder, including UNM-Valencia Campus and Valencia High School, were modeled using actual load values from the daylight hours minimum date and time.

Graph 3 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is OFF.

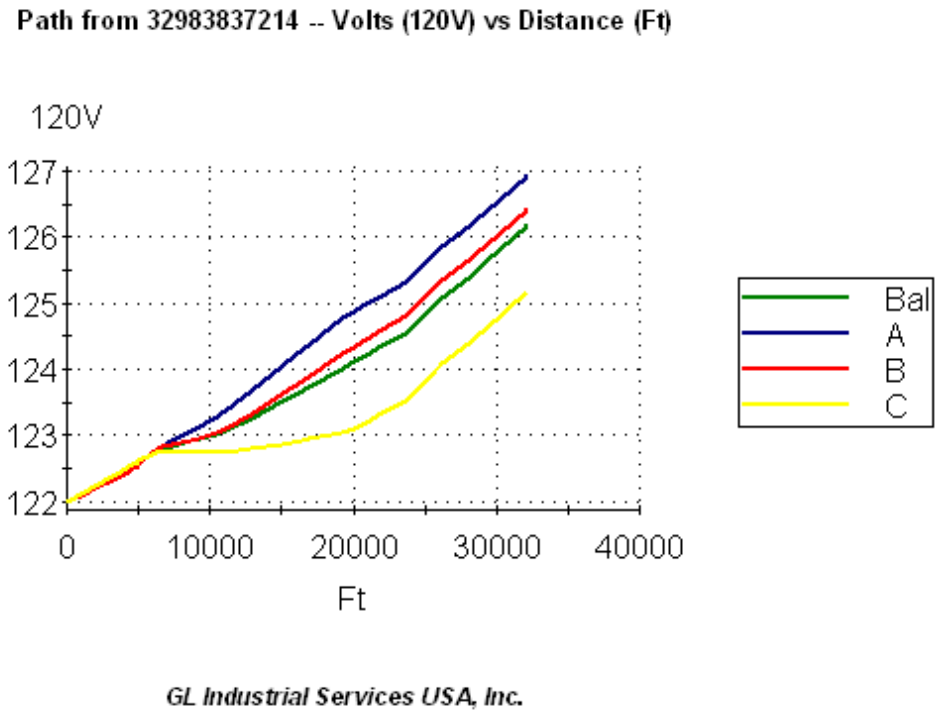


The model voltages at the point of interconnection are:

Phase A – 120.8 volts Phase B – 120.3 volts Phase C – 118.8 volts Balanced – 120.0 Volts.

The voltages on Manzano Feeder 13 prior to the installation of Project Tome are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is ON, 100% power factor.

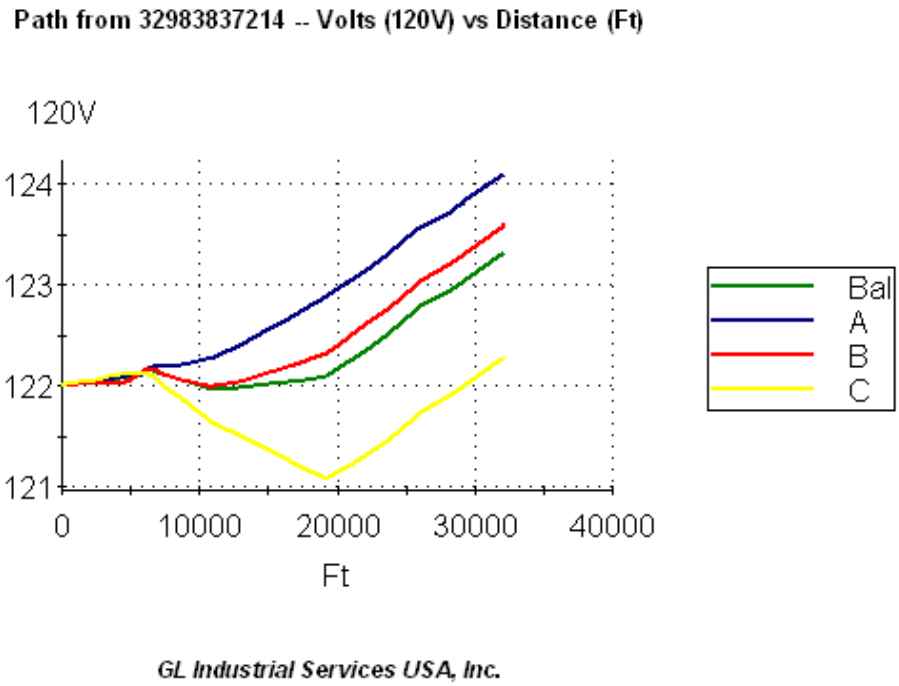


The model voltages at the point of interconnection are:

Phase A – 126.9 volts Phase B – 126.4 volts Phase C – 125.2 volts Balanced – 126.2 volts.

The voltages on Manzano Feeder 13 after the installation of Project Tome operating at 100% power factor are not within the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. Voltage control utilizing power factor correction will be needed at minimum loading timeframes.

Graph 5 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is ON, 98.5% lagging power factor.



The model voltages at the point of interconnection are:
Phase A – 124.1 volts Phase B – 123.6 volts Phase C – 122.3 volts Balanced – 123.3 Volts.

The voltages on Manzano Feeder 13 after the installation of Project Tome operating at 98.5% lagging power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion, for normal configuration, Project Tome output does cause the voltage on Manzano Feeder 13 to increase, if allowed to operate at 100% power factor. The voltage increase is not acceptable. Operating at 98.5% lagging power factor, the voltage stays within the PNM criteria of ANSI C84.1 and is acceptable, the inverters would be operating at 6 MVA, but the real power output is limited to 5.91 MW.

4.4 Voltage impacts for maximum daylight hours load for contingency configuration

Presently, there are two possible scenarios for contingency configuration that Project Tome can contribute to. The first is for the loss of Manzano Substation and the second is for the loss of Tome Substation.

Table 6 shows the maximum and minimum daylight hours loading on Tome Feeder 12.

Table 6 ***- Tome Feeder 12 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
August 4,2009	6 PM	5,192	443	5,211	99.6	219	272	226
May 25, 2009	7 AM	1,425	-475	1,502	-94.9	76	62	67

The results from the Synergee model for the maximum and minimum daylight hours loading on Tome Feeder 12 after a load transfer from Tome Feeder 12 to Manzano Feeder 13 are shown in Table 7.

Table 7 ***- Tome Feeder 12 max/min Daylight Hours Load After Load Transfer***

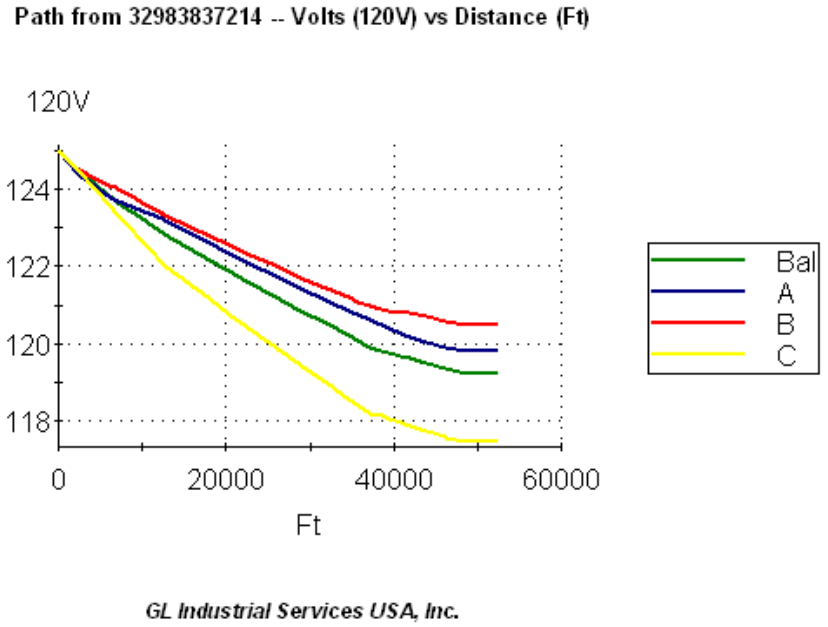
DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
August 4,2009	6 PM	4,590	81	4,591	99.9	190	244	193
May 25, 2009	7 AM	1,197	-584	1,332	-89.9	69	55	59

4.4.1 Contingency configuration – Loss of Manzano Substation, maximum load

For the loss of the Manzano Substation, a portion of Manzano Feeder 13 is transferred to El Cerro Substation through El Cerro Feeder 11 and a portion is transferred to Tome Substation through Tome Feeder 12. Project Tome is connected to the portion that gets transferred to Tome Feeder 12. For this study, the load that was previously transferred to Manzano Feeder 13 will be transferred back to Tome Feeder 12 for contingency. Voltage for the feeder daylight hours maximum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 6, 7 and 8. Larger customer loads on the feeder, including UNM-Valencia Campus and Valencia High School, were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from Tome Substation to the Project Tome point of interconnection (POI) is about 52,424 ft. or 9.93 miles.

Prior to the installation of Project Tome, contingency configuration for the loss of Manzano Substation at peak load timeframes require the Tome Substation LTC to be raised to 125 volts, which is shown in graph 6. This adjustment to the LTC is not required to support system voltages at minimum load timeframes, or when Project Tome is online, which can be seen in graphs 7 -11.

Graph 6 - Tome Feeder 12 voltage drop from Tome Substation to the Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is OFF.

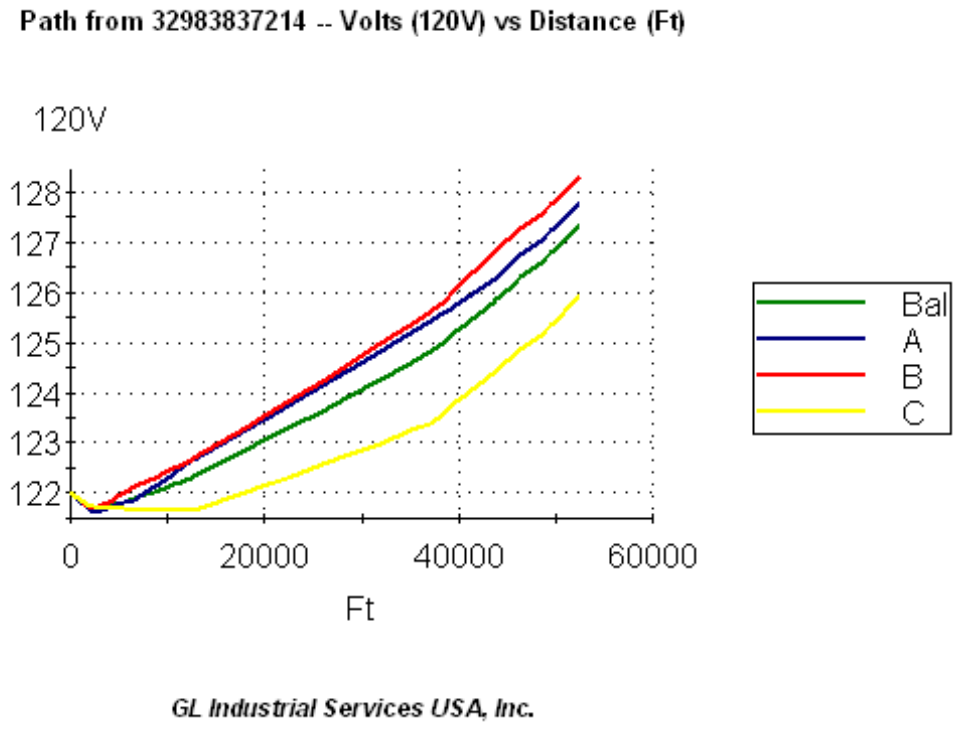


The model voltages at the point of interconnection are:

Phase A – 119.8 volts Phase B – 120.5 volts Phase C – 117.5 volts Balanced – 119.3 volts

The voltages on Tome Feeder 12 for the loss of Manzano Substation contingency prior to the installation of Project Tome are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 7 - Tome Feeder 12 voltage drop from Tome Substation to the Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is ON, at 100% power factor.

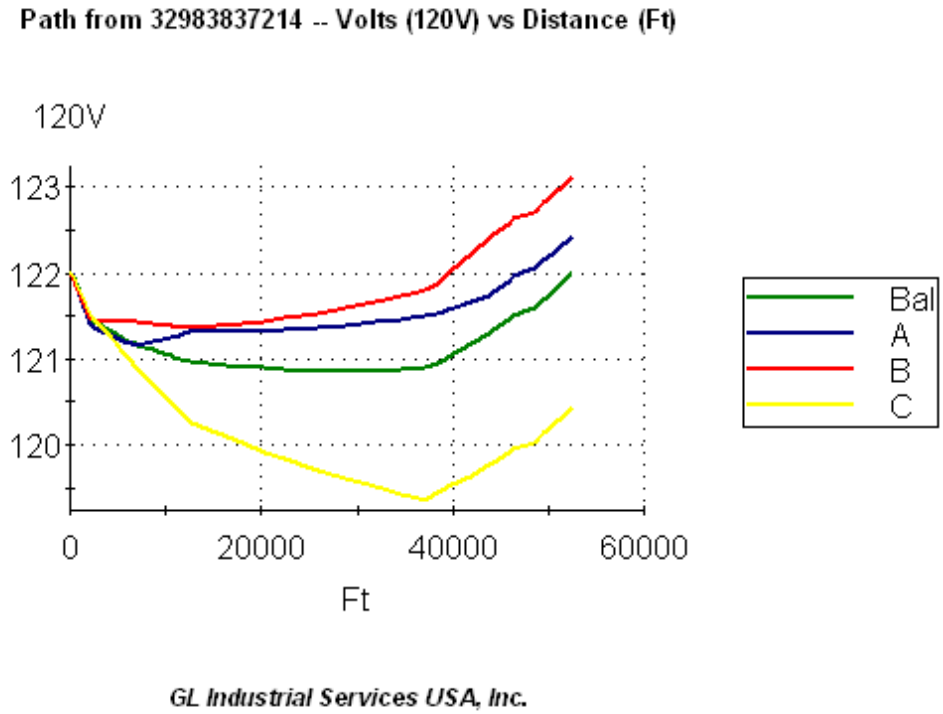


The model voltages at the point of interconnection are:

Phase A – 127.8 volts Phase B – 128.3 volts Phase C – 125.9 volts Balanced – 127.3 volts

The voltages on Tome Feeder 12 for the loss of Manzano Substation contingency after the installation of Project Tome operating at 100% power factor are not within the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. Voltage control utilizing power factor correction will be needed at maximum loading timeframes.

Graph 8 - Tome Feeder 12 voltage drop from Tome Substation to the Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is ON, 98.5% lagging power factor.



The model voltages at the point of interconnection are:

Phase A – 122.4 volts Phase B – 123.1 volts Phase C – 120.4 volts Balanced – 122.0 Volts.

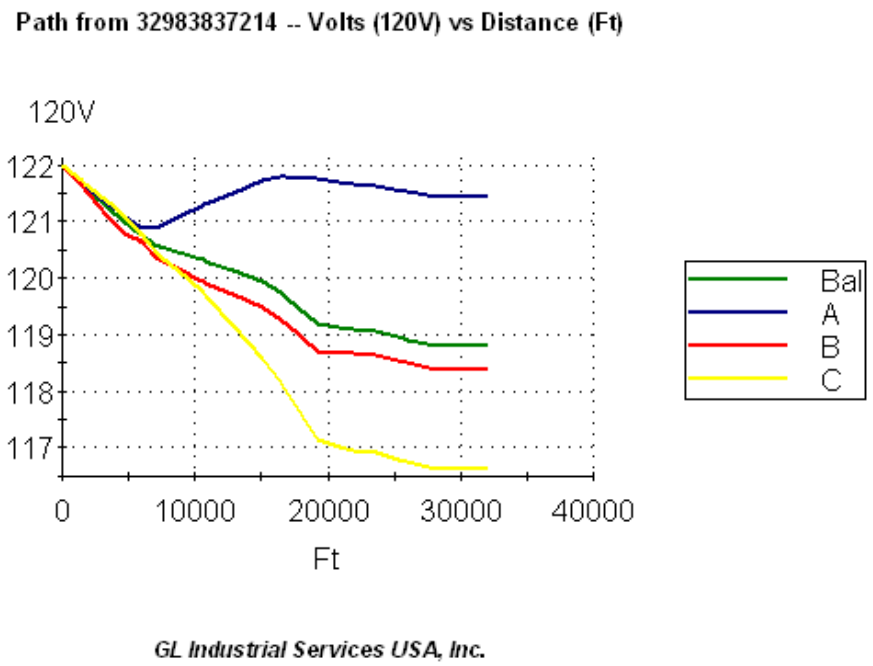
The voltages on Tome Feeder 12 for the loss of Manzano Substation contingency after the installation of Project Tome operating at 98.5% lagging power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4.2 Contingency configuration – Loss of Tome Substation, maximum load

For the loss of the Tome Substation, 10% of Tome Feeder 12 is transferred to Manzano Feeder 13. Voltage for the feeder daylight hours maximum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 9, 10 and 11. Larger customer loads on the feeder, including UNM-Valencia Campus and Valencia High School, were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from

Manzano Substation to the Project Tome POI is the same as was stated earlier for normal configuration.

Graph 9 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is OFF.

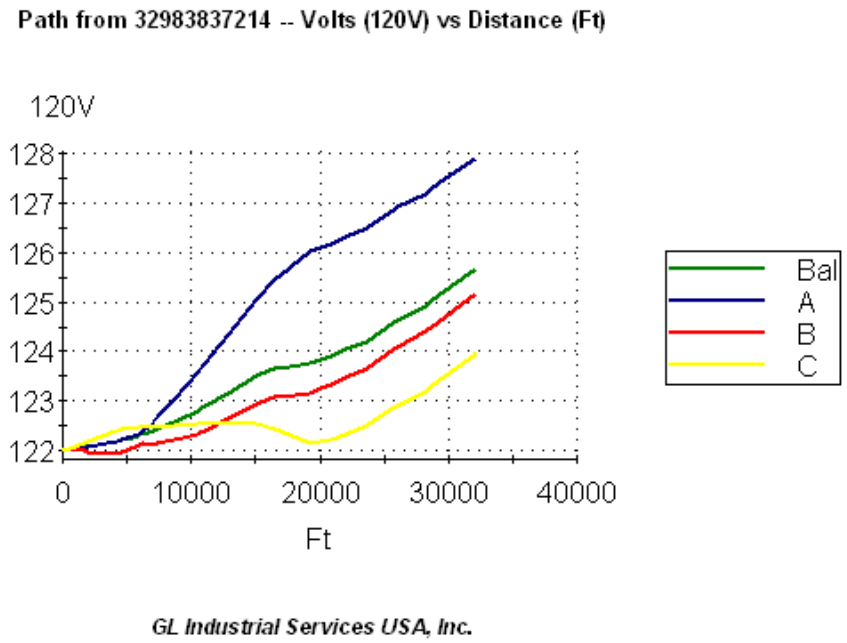


The model voltages at the point of interconnection are:

Phase A – 121.4 volts Phase B – 118.4 volts Phase C – 116.6 volts Balanced – 118.8 volts

The voltages on Manzano Feeder 13 for the loss of Tome Substation contingency prior to the installation of Project Tome are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 10 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is ON, at 100% power factor.

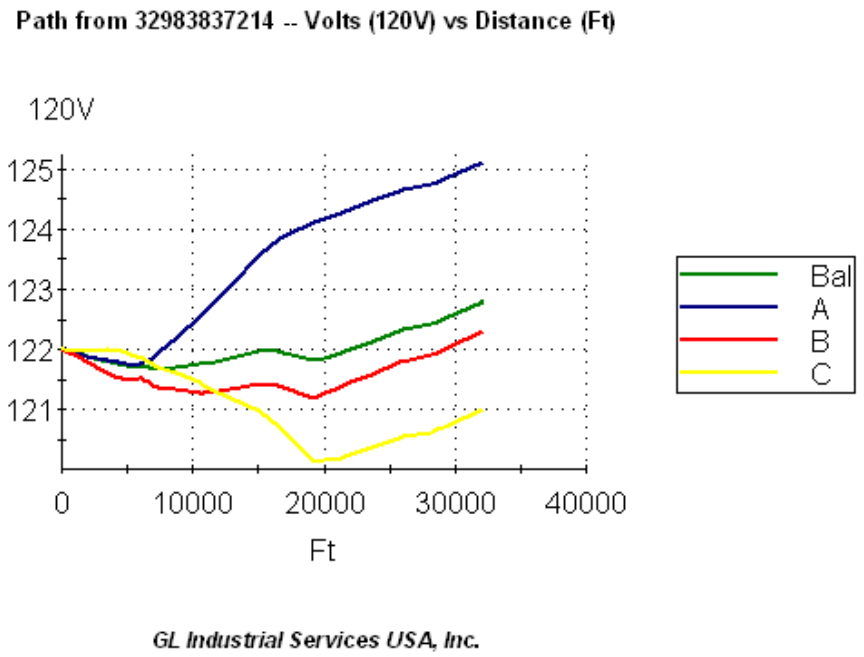


The model voltages at the point of interconnection are:

Phase A – 127.9 volts Phase B – 125.2 volts Phase C – 124.0 volts Balanced – 125.7 volts

The voltages on Manzano Feeder 13 for the loss of Tome Substation contingency after the installation of Project Tome operating at 100% power factor are not within the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. Voltage control utilizing power factor correction will be needed at maximum loading timeframes.

Graph 11 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours maximum load on July 13, 2009. Project Tome is ON, 98.5% lagging power factor.



The model voltages at the point of interconnection are:
Phase A – 125.1 volts Phase B – 122.3 volts Phase C – 121.0 volts Balanced – 122.8 Volts.

The voltages on Manzano Feeder 13 for the loss of Tome Substation contingency after the installation of Project Tome operating at 98.5% lagging power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5 Voltage impacts for minimum daylight hours load for contingency configuration

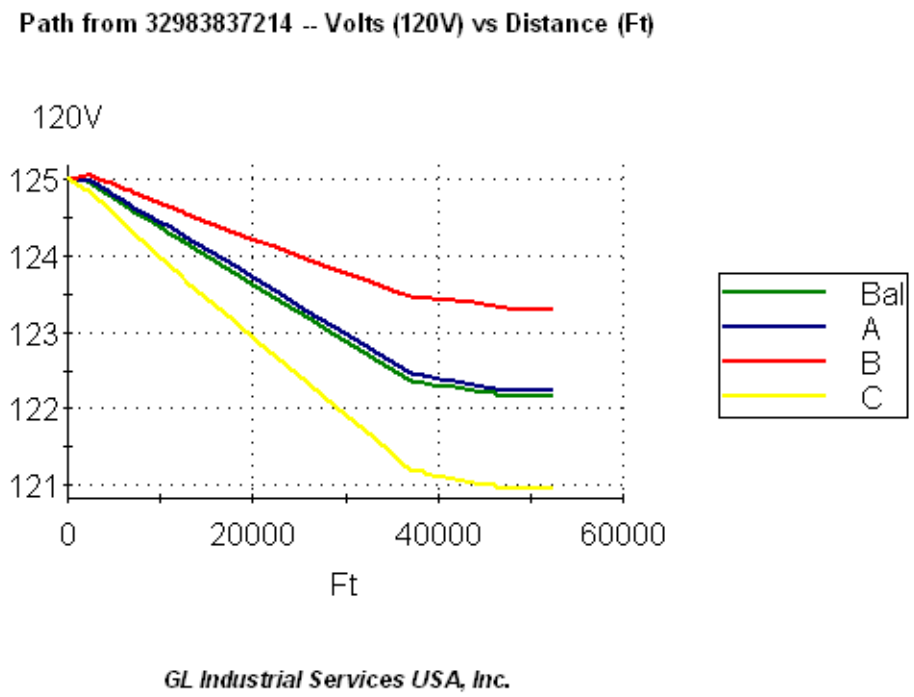
4.5.1 Contingency configuration – Loss of Manzano Substation, minimum load

For the loss of the Manzano Substation, Project Tome is connected to the portion that is transferred to Tome Feeder 12. For this study, the load that was previously transferred to Manzano Feeder 13 will be transferred back to Tome Feeder 12 for contingency. Voltage for

the feeder daylight hours minimum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 12, 13 and 14. Larger customer loads on the feeder, including UNM-Valencia Campus and Valencia High School, were modeled using actual load values from the daylight hours minimum date and time.

Prior to the installation of Project Tome, contingency configuration for the loss of Manzano substation require the Tome Substation LTC to be raised to 125 volts, which is shown in graph 12. This adjustment to the LTC is not required to support system voltages at minimum load timeframes, or when Project Tome is online, which can be seen in graphs 13 -17.

Graph 12 - Tome Feeder 12 voltage drop from Tome Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is OFF.

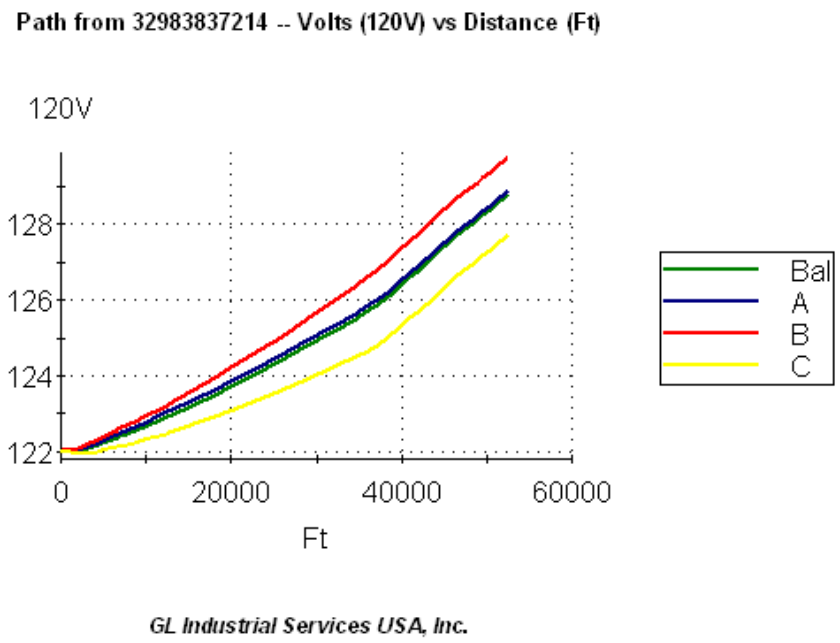


The model voltages at the point of interconnection are:

Phase A – 122.2 volts Phase B – 123.3 volts Phase C – 121.0 volts Balanced – 122.2 volts.

The voltages on Tome Feeder 12 for the loss of Manzano Substation contingency prior to the installation of Project Tome are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 13 - Tome Feeder 12 voltage drop from Tome Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is ON, at 100% power factor.

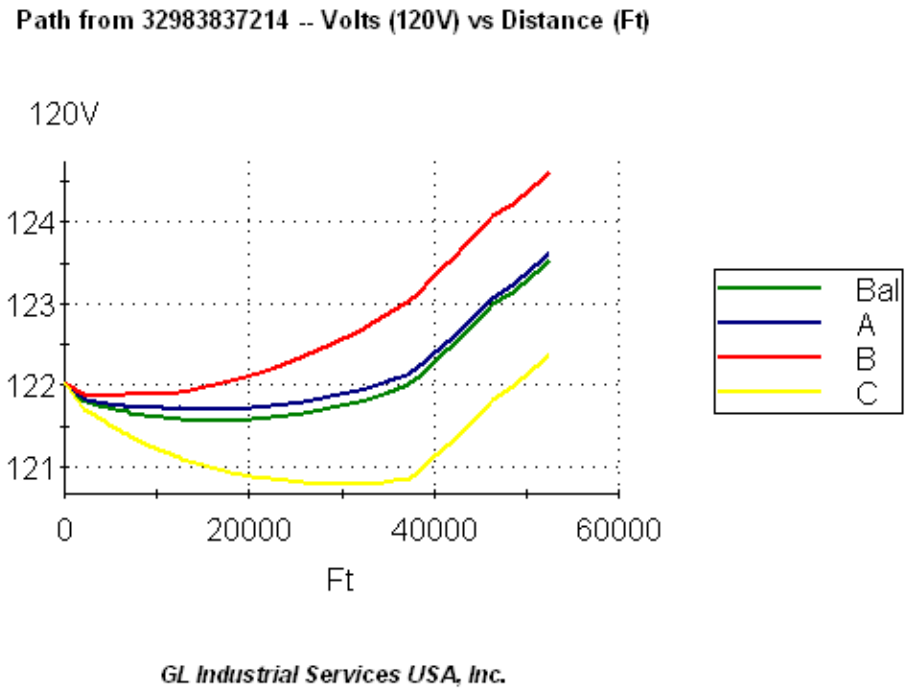


The model voltages at the point of interconnection are:

Phase A – 128.9 volts Phase B – 129.8 volts Phase C – 127.7 volts Balanced – 128.8 volts

The voltages on Tome Feeder 12 for the loss of Manzano Substation contingency after the installation of Project Tome operating at 100% power factor are not within the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. Voltage control utilizing power factor correction will be needed at minimum loading timeframes.

Graph 14 - Tome Feeder 12 voltage drop from Tome Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is ON, at 98.5% lagging power factor.



The model voltages at the point of interconnection are:

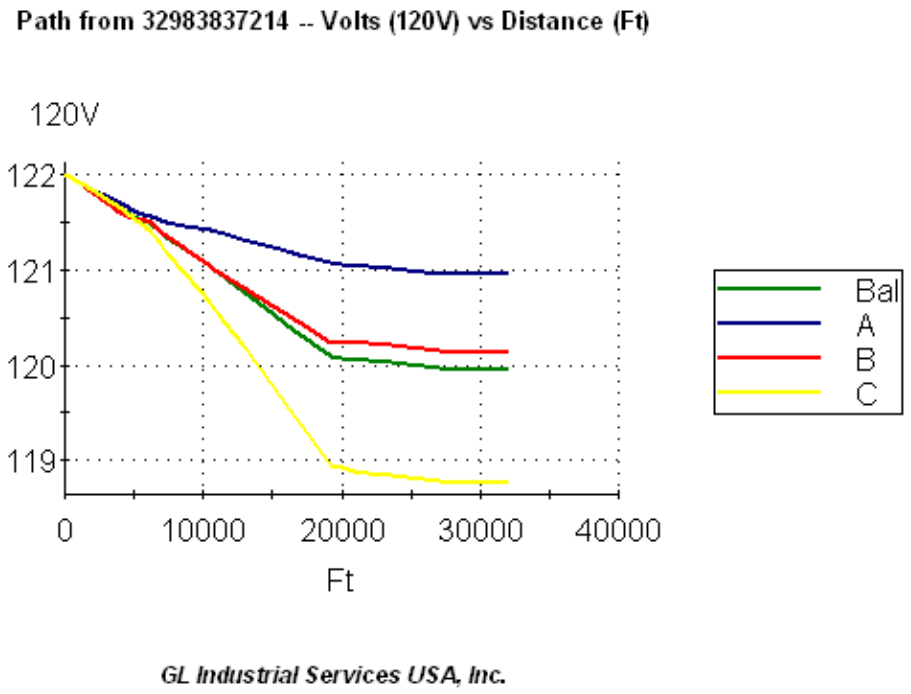
Phase A – 123.6 volts Phase B – 124.6 volts Phase C – 122.4 volts Balanced – 123.5 volts

The voltages on Tome Feeder 12 for the loss of Manzano Substation contingency after the installation of Project Tome operating at 98.5% lagging power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5.2 Contingency configuration – Loss of Tome Substation, minimum load

For the loss of the Tome Substation, 10% of Tome Feeder 12 is transferred to Manzano Feeder 13. Voltage for the feeder daylight hours minimum load for 2009 with and without Project Tome, per the Synergee model, are shown in Graphs 15, 16 and 17. Larger customer loads on the feeder, including UNM-Valencia Campus and Valencia High School, were modeled using actual load values from the daylight hours minimum date and time. The circuit distance from Manzano Substation to the Project Tome POI is the same as was stated earlier for normal configuration.

Graph 15 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is OFF.

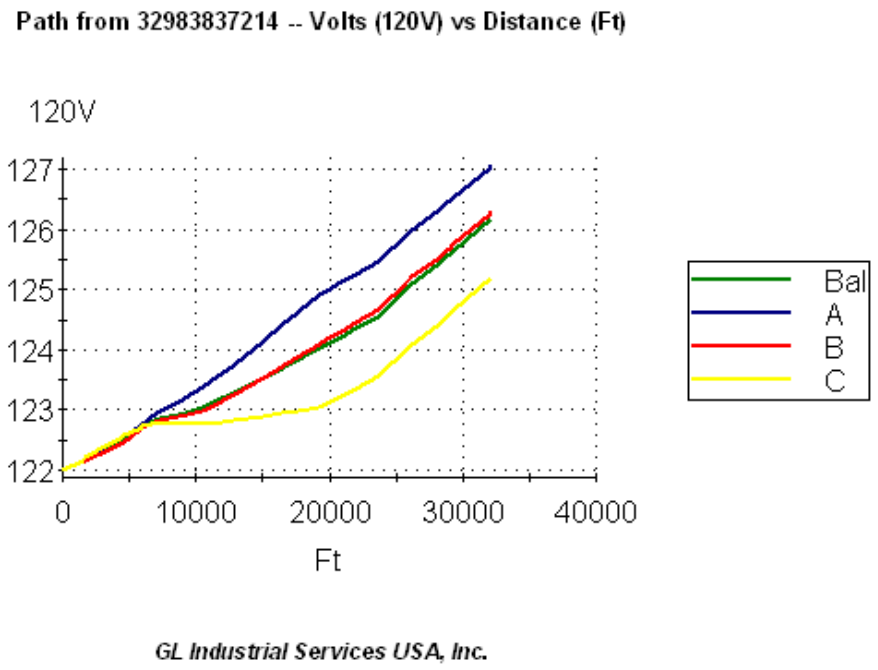


The model voltages at the point of interconnection are:

Phase A – 120.9 volts Phase B – 120.1 volts Phase C – 118.8 volts Balanced – 119.9volts

The voltages on Manzano Feeder 13 for the loss of Tome Substation contingency prior to the installation of Project Tome are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 16 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is ON, at 100% power factor.

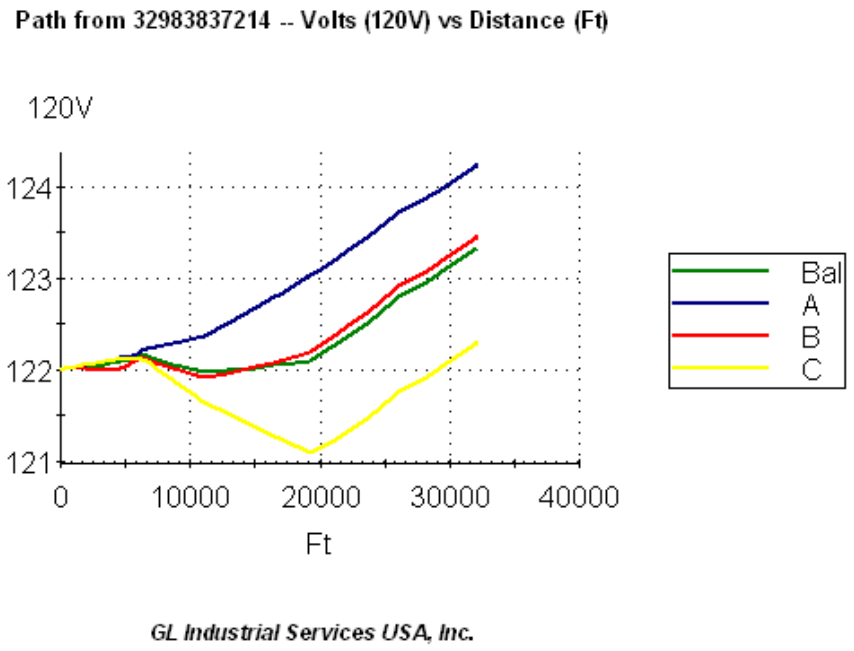


The model voltages at the point of interconnection are:

Phase A – 127.1 volts Phase B – 126.3 volts Phase C – 125.2 volts Balanced – 126.2 volts

The voltages on Manzano Feeder 13 for the loss of Tome Substation contingency after the installation of Project Tome operating at 100% power factor are not within the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. Voltage control utilizing power factor correction will be needed at minimum loading timeframes.

Graph 17 - Manzano Feeder 13 voltage drop from Manzano Substation to the Project Tome POI for daylight hours minimum load on May 24, 2009. Project Tome is ON, 98.5% lagging power factor.



The model voltages at the point of interconnection are:

Phase A – 124.2 volts Phase B – 123.5 volts Phase C – 122.3 volts Balanced – 123.3 Volts.

The voltages on Manzano Feeder 13 for the loss of Tome Substation contingency after the installation of Project Tome operating at 98.5% lagging power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion, Project Tome output does cause the voltage on Manzano Feeder 13 and on Tome Feeder 12 for contingency conditions to increase. Operating at 100% power factor, the voltage increase is not acceptable. Operating at 98.5% lagging power factor, the voltage stays within the PNM criteria of ANSI C84.1 and is acceptable.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer ("LTC") of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Tome is served by Manzano Feeder 13, and there is no voltage regulator installed on the feeder. The substation LTC is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 120.5 volts and will reduce the voltage if the substation bus is above 123.5 volts.

As seen in Tables 8 -13, the Synergee modeling shows the LTC changed 1 position for 6,000 KW source on the feeder for high or low load periods. This LTC operation is not considered an adverse impact.

Project Tome was modeled as a source on Manzano Substation connected to the end of Manzano Feeder 13. The Synergee model included the substation transformer and Manzano Feeders 11, 12 and 13. The substation bus voltage and load tap changer position for maximum daylight hours load for 2009 with and without Project Tome 6MW, per the Synergee model, are shown in Tables 8, 9 and 10.

***Table 8* - Manzano Substation with Project Tome OFF for daylight hours maximum load on July 13, 2009**

	MANZANO SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.5	122.3	122.6	122.1
LTC position	2 raise	2 raise	2 raise	

The model voltages at the substation bus are shown in Table 8. The voltages at Manzano Substation prior to the installation of Project Tome are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 9 ***- Manzano Substation with Project Tome ON, at 100% power factor for daylight hours maximum load on July 13, 2009***

	MANZANO SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.4	122.1	122.4	122.0
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 9. The voltages at Manzano Substation after to the installation of Project Tome at 100% power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 10 ***- Manzano Substation with Project Tome ON, at 98.5% lagging power factor for daylight hours maximum load on July 13, 2009***

	MANZANO SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.4	122.1	122.4	122.0
LTC position	2 raise	2 raise	2 raise	

The model voltages at the substation bus are shown in Table 10. The voltages at Manzano Substation after to the installation of Project Tome at 98.5% lagging power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The Manzano Feeder 13 voltage for the feeder minimum daylight hours load for 2009 with and without Project Tome, per the Synergee model, are shown in Tables 11, 12 and 13.

Table 11 ***- Manzano Substation with Project Tome OFF for daylight hours minimum load on May 24, 2009***

	MANZANO SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.7	121.7	121.7	121.7
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 11. The voltages at Manzano Substation prior to the installation of Project Tome are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable. The minimum load was modeled with one 1,200 KVAR capacitor bank on Manzano Feeder 13 de-energized and one energized.

Table 12 ***- Manzano Substation with Project Tome ON, at 100% power factor for daylight hours minimum load on May 24, 2009***

	MANZANO SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.9	121.9	121.9	121.9
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 12. The voltages at Manzano Substation after to the installation of Project Tome at 100% power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable. The minimum load was modeled with the one 1,200 KVAR capacitor bank on Manzano Feeder 13 de-energized and one energized.

Table 13 ***- Manzano Substation with Project Tome ON, at 98.5% lagging power factor for daylight hours minimum load on May 24, 2009***

	MANZANO SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.9	121.9	121.9	121.9
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 13. The voltages at Manzano Substation after the installation of Project Tome at 98.5% lagging power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable. The minimum load was modeled with the one 1,200 KVAR capacitor bank on Manzano Feeder 13 de-energized and one energized.

In conclusion, the voltage on Manzano Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of Project Tome output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company ("GE") developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC

does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Manzano Substation bus was fixed at 122 volts with and without Project Tome output for maximum and minimum load periods. Table 14 summarizes the balanced voltage and the calculated voltage flicker. Table 15 is based on the GE flicker graph.

Table 14 ***- Voltage flicker on at the POI due to Project Tome***

	Project Tome POI Bus Voltage	
	Minimum	**Maximum**
Without Project	120.0	117.7
With Project	123.3	121.5
% Voltage Flicker	**2.75**	**3.23**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 15 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
2.75	1/hour	15/hour
3.23	Always Visible	10/hour

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 14 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 15. Results are less than the 6% criteria; therefore distribution voltage flicker resulting from changes in Project Tome output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Tome POI to the substation were reviewed using the Synergee feeder model with and without Project Tome's maximum output of 6,000 KW AC.

There were no conductor loading problems from the POI to the substation on Manzano Feeder 13 with Project Tome OFF. However, with Project Tome at maximum output, there were conductor loading problems on approximately 1000 ft. of 2 ACSR, which is rated 190 amps for normal and emergency. The Synergee model showed the section loads as A-phase – 271 amps, B-phase – 274 amps and C-phase -278 amps. These sections of 2 ACSR will need to be reconductored with 397 AAC as part of the line extension to connect Project Tome to the feeder.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station ("RCCS") program. The RCCS program polls the System Control and Data Acquisition ("SCADA") system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. For this study, Project Tome was found to cause adverse impacts on the system at 100% power factor. The SMA SC 500SC inverter is capable of operating at a fixed power factor within the 95% leading to 95% lagging range. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Manzano Feeder 13 has two 1,200 KVAR RCCS controlled capacitor banks and one 600 KVAR fixed capacitor bank. The July 2009 peak load on the feeder was 5,688 KW + j1,002 KVAR or 5,775 KVA at a 98.5% lagging power factor. Only one switched capacitor and the fixed capacitor were energized during the peak load period, due to the other switched bank getting installed after the 2009 peak period. The newly installed switched capacitor bank is anticipated to be energized for peak load periods. The Synergee model shows the 2009 load after the transfer from Tome Feeder 12 is 6,348 KW + 158 KVAR or 6,350 KVA at a 99.9% lagging power factor with all three capacitor banks energized. Project Tome at 98.5% power factor would change the apparent feeder loading to 439 KW + j1,196 KVAR or 1,274 KVA at 35% power factor. This power factor value exceeds the RCCS power factor control point, but all capacitors are energized prior to this condition, therefore any issues addressed would be driven by pre-existing conditions. The power factor does indeed appear to become worse, but the Synergee model shows that there are no voltage or thermal problems associated with this condition. This study examined the conditions of turning off RCCS capacitor banks, to reduce the voltage to see what affects they would have on the system and to analyze the affect of the inverter operating at 100% power factor. At minimum feeder load, with all RCCS controlled capacitor banks offline, the voltage on the feeder still exceeded the PNM criteria of ANSI C84.1. Therefore, voltage control utilizing power factor correction will be needed.

Tome Feeder 12 has one 1,200 KVAR RCCS capacitor bank and one 600 KVAR fixed bank. During the contingency analysis for the loss of Manzano Substation, all capacitor banks were assumed to be on for the peak load timeframe and the RCCS capacitor bank was assumed to be off for the minimum load timeframe. The remotely controlled capacitor banks on the feeder may potentially be de-energized, but this does not adversely impact voltages.

9.0 PROTECTION

9.1 Normal Configuration – Service from Manzano Substation Feeder 13

Manzano Substation Feeder 13 is protected by a 1200 amp breaker in metal clad switchgear with a GE, MDP extremely inverse phase overcurrent relay and a very inverse ground overcurrent relay. There is also an ABB, MMCO extremely inverse phase overcurrent relays and a very inverse ground overcurrent relay. There is also a GE, SLR reclosing relay. The

switchgear bus and feeder backup protection is an ABB, MMCO very inverse phase relay and an ABB, MMCO very inverse ground relay. There is also a GE, MDP very inverse phase relay. The transformer protection is three GE, STD differential relays. The Tome Project PV system will be connected to the system approximately 6.07 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in Synergee to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder; however the available fault current from the PV system may be higher than the ground pickup on the feeder relay. The unit sub protection scheme includes a lockout relay wired to trip the feeder breakers and circuit switcher for a bus fault.

Project Tome does not require any system protection improvements to be made to the Manzano Substation Feeder 13.

9.2 Normal Feeder as a Backup Feeder – Manzano Feeder 13 picks up Tome Feeder 12

Fault analysis of the system when Manzano 13 is a backup feeder for Tome 12 was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in Synergee to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to a downstream Cooper Nova recloser. The available fault current at the recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination

with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder; however the available fault current from the PV system may be higher than the ground pickup on the feeder relay. The unit sub protection scheme includes a lockout relay wired to trip the feeder breakers and circuit switcher for a bus fault.

Project Tome does not require any system protection improvements to be made to the Manzano Substation Feeder 13 as a backup feeder for Tome 12.

9.3 Contingency Configuration – Tome Feeder 12 picks up Manzano Feeder 13

Tome Substation Feeder 12 is protected by a 1200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, HU differential relays. The Tome Project PV system will be connected to the system approximately 10.77 miles from the substation.

Fault analysis of the system for Tome 12 was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in Synergee to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to two downstream Cooper Nova reclosers. The available fault current at both reclosers, for faults on the system anywhere on the loadside of the reclosers is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was

reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder.

Project Tome does not require any system protection improvements to be made to the Tome Substation Feeder 12.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Tome output exceeds the 2009 minimum load on Manzano Feeder 13 during daylight hours. No Manzano Feeder 13 equipment overloads were identified.

Project Tome output exceeds the 2009 minimum load on Tome Feeder 12 during daylight hours. No Tome Feeder 12 equipment overloads were identified.

11.0 METERING and COMMUNICATION

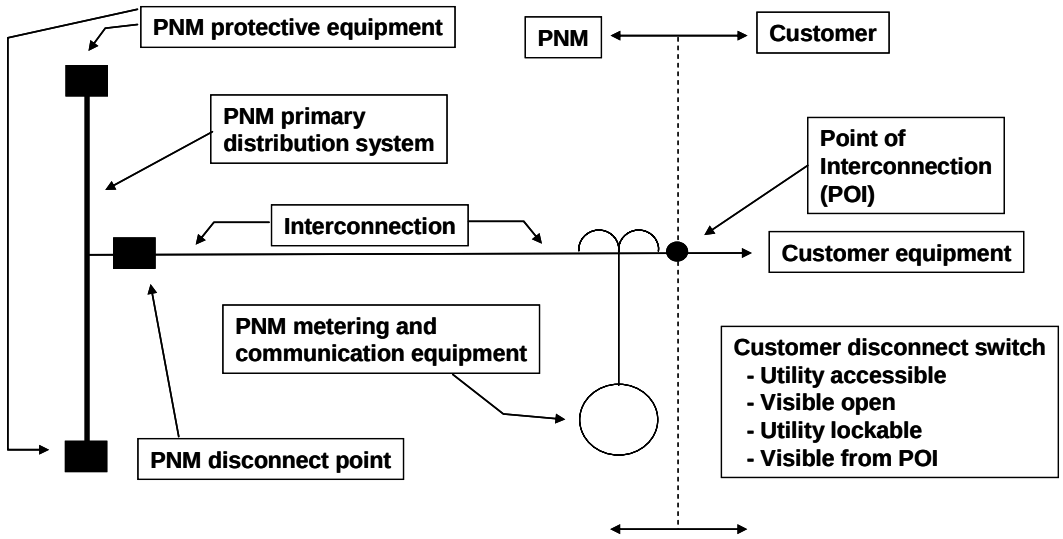
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is a one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project Tome to the PNM distribution system, system upgrades and a line extension are required. The interconnection consists of:

- Create a new open point on Tome Feeder 12 by installing a new pole and a normally open GOLB switch between poles F32C004 and F32C005 on Rio Del Oro Blvd. (See Figure 4).
- Build approximately 1,600 ft. of three-phase 750 UG AL feeder along Paseo De Vista Blvd. between the PMH-9 switch SW123V and the existing overhead line on Rio Del Oro Blvd. (See Figure 4).
- Reconductor approximately 1,039 ft. of 2 ACSR to 397 AAC (See Figure 5).

- Build approximately 2,800 ft. of new 397 AAC overhead circuit from pole F32C015 to the PV site location at the intersection of Rio Del Oro Loop N. and Bonita Vista Blvd. (See Figure 5).
- Install one S&C IntelliRupter switch (See Figure 5).
- Riser to primary meter, about 20 ft, using 750 AL (See Figure 5).

Figure 4 ***– System Upgrade to transfer load from Tome Feeder 12 to Manzano Feeder 13***

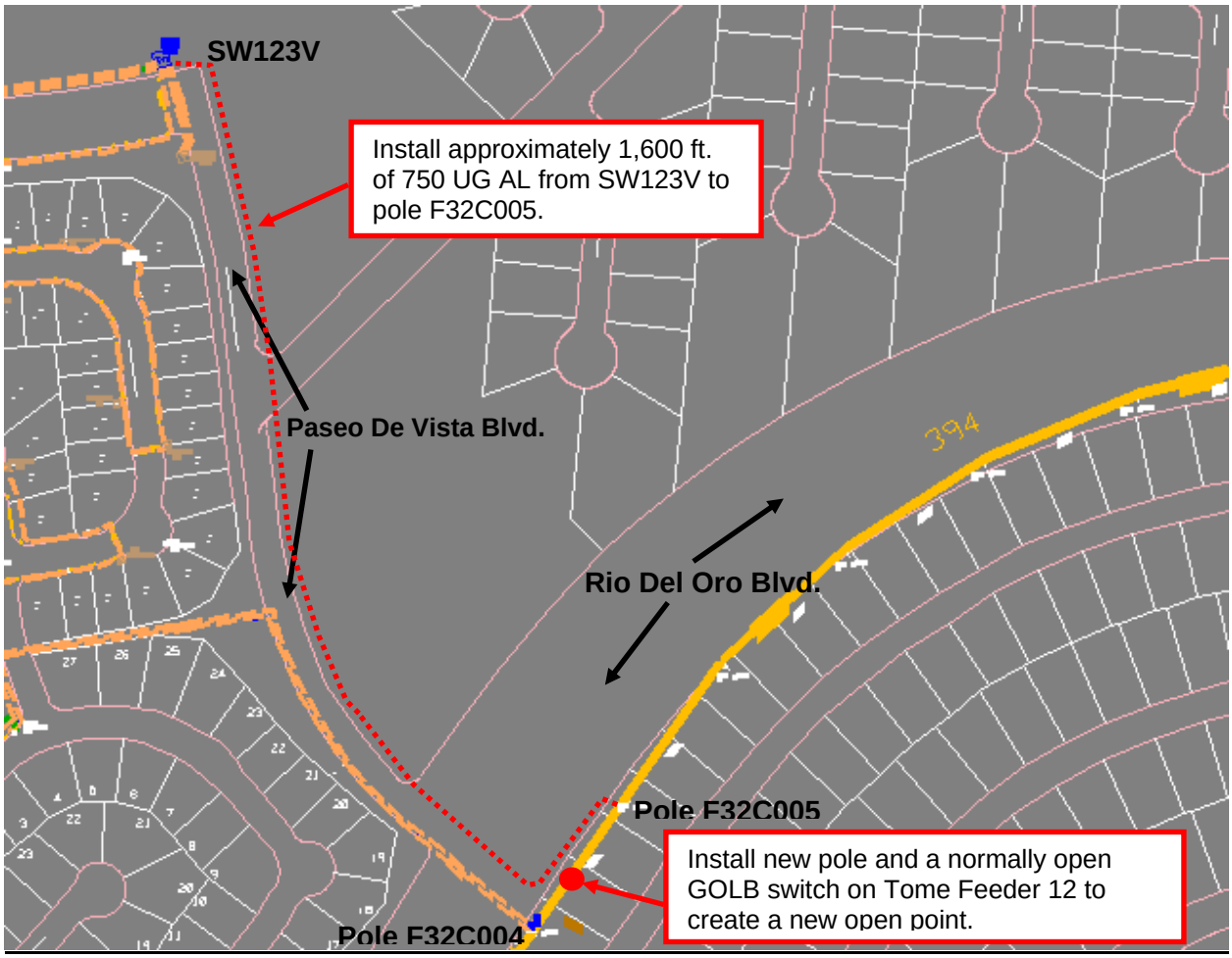
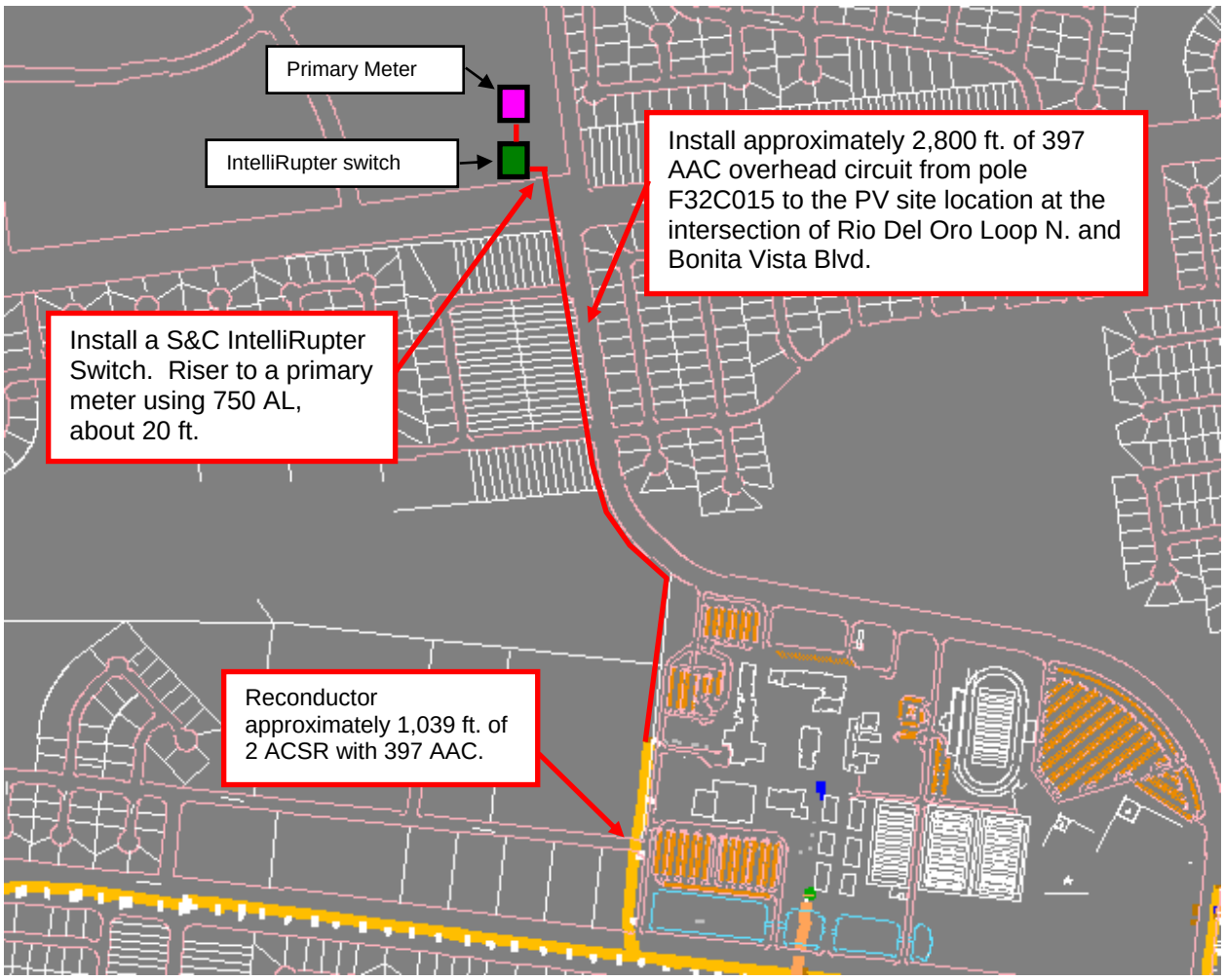


Figure 5 ***– System Upgrade to correct overloaded conductor and line extension for interconnection***



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 16.

Table 16 ***- Project Tome Interconnection Cost***

	ESTIMATED COSTS 2010$
PNM disconnect point (IntelliRupter)	$ 51,500
Interconnection (Line Construction)	$ 340,300
PNM Primary metering	$ 24,100
TOTAL	**$ 415,900**

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This may also involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition is not expected to be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA). The NOA may also require the facility to operate at 98.5% power factor importing VARS as a condition to maintain interconnection to the EPS.

16.0 CONCLUSIONS

Project Tome does have an adverse impact on the PNM distribution system when operating at 100% power factor. Voltage control must be maintained by operating at a fixed power factor of 98.5% lagging. The Project location will result in an interconnection with Manzano Feeder 13. When operating at a lagging 98.5% power factor, analysis shows voltages will remain within the PNM criteria of ANSI C84.1. There are two remotely controlled capacitor banks on the feeder associated with Project Tome. The automatic control of voltage by the substation LTC may cause the LTC to operate, but this is not anticipated to be an adverse effect. The Project output will cause a flow of electricity from the distribution system through the substation transformer, the difference is less than 5 MW, therefore no transmission voltage issues are anticipated. Analysis also showed that the Project output did cause some 2 ACSR conductor ratings to be exceeded. The estimated cost to reconductor these affected sections is included in the project interconnection cost. Finally, analysis shows that Project Tome output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Tome and has determined that there are no adverse impacts associated with a 6,000 KVA AC source connected to Manzano Substation with a dedicated distribution primary source of Manzano Feeder 13 when operated at a fixed lagging 98.5% power factor.

Distribution Planning has determined that system upgrades are required to ensure that electric service to all customers on Manzano Substation is maintained within established PNM voltage, equipment and fault protection criteria.

Public Service Company of New Mexico
Generation Planning and Development

Project Los Morros 6,000 KW PV Generation Project

Small Generator Interconnection Feasibility Study

(SGI-PNM-2010-08)

October 2010

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for Public Service Company of New Mexico Generation Planning and Development Department by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

Public Service Company of New Mexico Generation Planning and Development submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system with a nominal rating of 6,000 KW AC to the Public Service of New Mexico ("PNM") distribution primary system. The request is identified as Project Los Morros ("Project Los Morros" or "Project") and would be connected to Los Morros Feeder 21. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures ("SGIP") for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study was performed by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts ("Distribution Planning").

The estimated cost of connecting Project Los Morros to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (Intellirupter)	$ 51,000	~16 week lead time ~3 Days to build
Interconnection (Line Construction)	$ 68,300	~16 week lead time ~5 Days to build
PNM Primary metering	$ 24,500	~3 week lead time ~ 4 days to build
Communications	$ 45,000	~16 week lead time ~3 weeks to build
Protection	$ 90,000	
TOTAL	**$ 278,800**	**6-7 months for lead time and final build out.**

The technical data notes for the SMA SC 500CP inverter were used to prepare this report. The data shows that this inverter is presently not a certified UL 1741 compliant inverter. The SMA SC 500CP inverter will have a 1000V DC rating and is designed to meet UL 1741 compliance standards. Since UL testing is limited to 600V systems the project is requesting a variance to

the UL 1741 compliance standard. Based on the manufacturer technical data notes the inverter is capable of maintaining a unity power factor and this System Impact Study ("Study") assumed that the facility maintained unity power factor. Distribution Planning recommends the use of a UL listed 1741 compliant inverter to insure that, among other concerns, that the unit will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other various requirements as called out in the SGIP application, Attachment 3. A complete field checkout of non-complaint equipment at the proposed facility is recommended before the facility can be considered certified for interconnection operation.

This Study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Los Morros does not have an adverse impact on the PNM distribution system.

The Project location will result in an interconnection with Los Morros Feeder 21 and the analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds are not anticipated to cause voltage flicker problems.
4. Project output did not cause conductor ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does require system protection upgrades to be made to the Los Morros Feeder 21 for both normal and for contingency configurations.
7. Project output will cause a flow of electricity from the distribution system through the substation transformer, but this is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Los Morros and has determined that there are no adverse impacts associated with a 6,000 KW AC source connected to Los Morros Unit II Substation when connected to Los Morros Feeder 21.

Distribution Planning has determined that system upgrades are required to ensure that electric service to all customers on Los Morros Unit II Substation is maintained within established PNM voltage, equipment and fault protection criteria.

1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a photovoltaic ("PV") electric generation source connected to the distribution primary system identified as Project Los Morros. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Los Morros proposes to connect a 6,000 KW AC PV facility to Los Morros Feeder 21 in Los Lunas, NM. The Project Los Morros is located on the northwest corner of Sand Sage and Los Morros Rd. as shown in Figure 1. The circuit distance from Los Morros Unit II Substation to the Project Los Morros point of interconnection ("POI") is about 4,155 ft. or 0.79 miles.

***Figure 1* – Project Los Morros Location**

3.0 SYSTEM CONFIGURATION

Project Los Morros is a large PV source and is proposed to be connected to Los Morros Feeder 21 served from Los Morros Unit II Substation. Table 1 shows the rating of Los Morros Unit II Substation as determined by the EPRI Ptload program.

Table 1 ***- Substation transformer nameplate versus Ptload rating***

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Los Morros Unit II	22.40	23.50	26.20	115-12.47

Table 2 shows the 2009 peak summer loads for Los Morros Unit II Substation and feeders, this data is not coincident with PNM's 2009 system wide peak demand timeframe.

Table 2 ***- July 2009 Non-coincident Peak Loads***

Feeder	July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Los Morros 21	1,587	901	1,825	86.9
Los Morros 22	0	0	0	0
Los Morros 23	4,125	1,499	4,389	94.0
Los Morros 24	0	0	0	0
Los Morros Unit II Sub	5,595	2,126	5,985	93.5

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Los Morros Feeder 21 are shown in Table 3:

Table 3 *- Los Morros Feeder 21 max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 16,2009	6 PM	1,529	829	1,739	87.9	76	71	89
Oct. 25, 2009	3 PM	216	101	238	90.7	9	8	16

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Los Morros at maximum output exceeds the load on Los Morros Feeder 21. Therefore, Project Los Morros will cause a flow of power into Los Morros Unit II Substation. Table 4 shows the maximum and minimum load on the Los Morros Unit II Substation transformer.

Table 4 *- Los Morros Unit II Substation max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 8,2009	7 PM	5,588	2,142	5,984	93.4	243	245	331
October 25, 2009	7 AM	919	-71	921	-99.8	37	39	54

Project Los Morros at maximum output, exceeds the load on the Los Morros Unit II Substation transformer. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system.

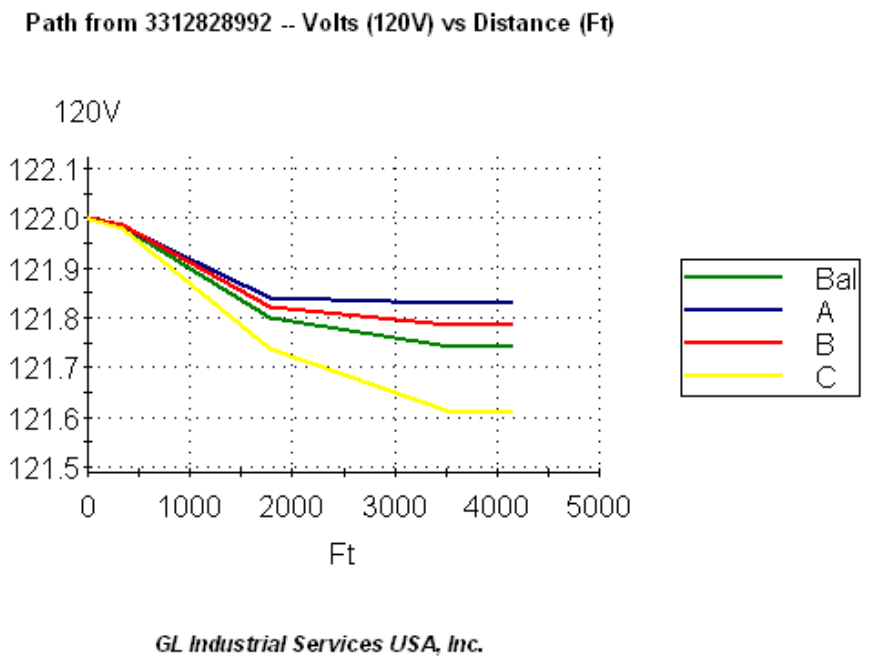
4.1 Voltage impacts on the transmission system

Although the load on the Los Morros Unit II Substation transformer is less than the rated output of the project, the difference is approximately 5 MW, therefore no transmission related issues are anticipated to be associated with Project Los Morros.

4.2 Voltage impacts for maximum daylight hours load for normal configuration

The Los Morros Feeder 21 voltage for the feeder daylight hours maximum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 1 and 2. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours maximum date and time.

Graph 1 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to Project Los Morros POI for daylight hours maximum load on July 16, 2009. Project Los Morros is OFF.

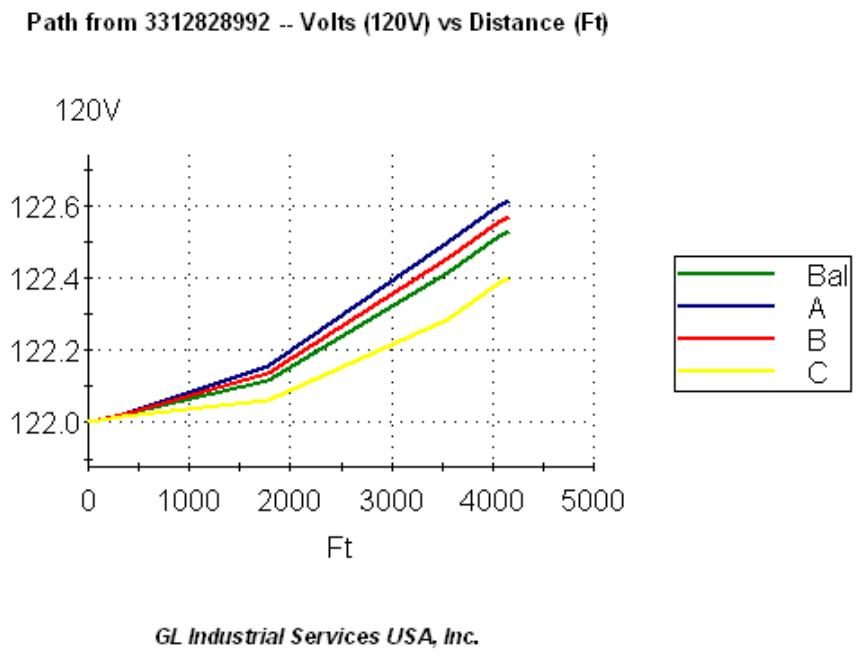


The model voltages at the point of interconnection are:

Phase A – 121.8 volts Phase B – 121.8 volts Phase C – 121.6 volts Balanced – 121.7 volts

The voltages on Los Morros Feeder 21 prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to Project Los Morros POI for daylight hours maximum load on July 16, 2009. Project Los Morros is ON, 100% power factor.



The model voltages at the point of interconnection are:

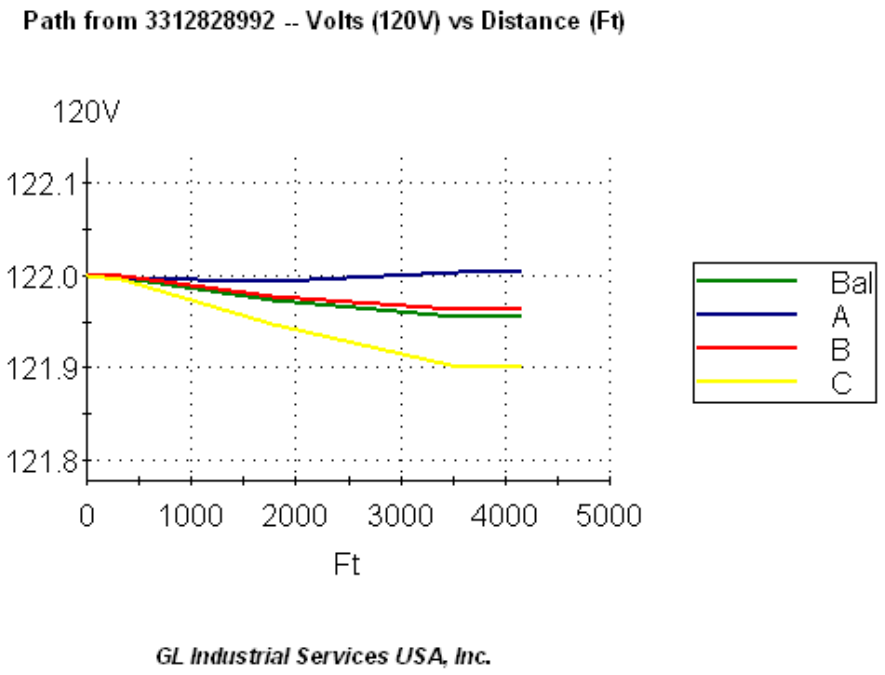
Phase A – 122.6 volts Phase B – 122.6 volts Phase C – 122.4 volts Balanced – 122.5 volts

The voltages increase on Los Morros Feeder 21 after the installation of Project Los Morros but are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.3 Voltage impacts for minimum daylight hours load for normal configuration

The Los Morros Feeder 21 voltage for the feeder daylight hours minimum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 3 and 4. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours minimum date and time.

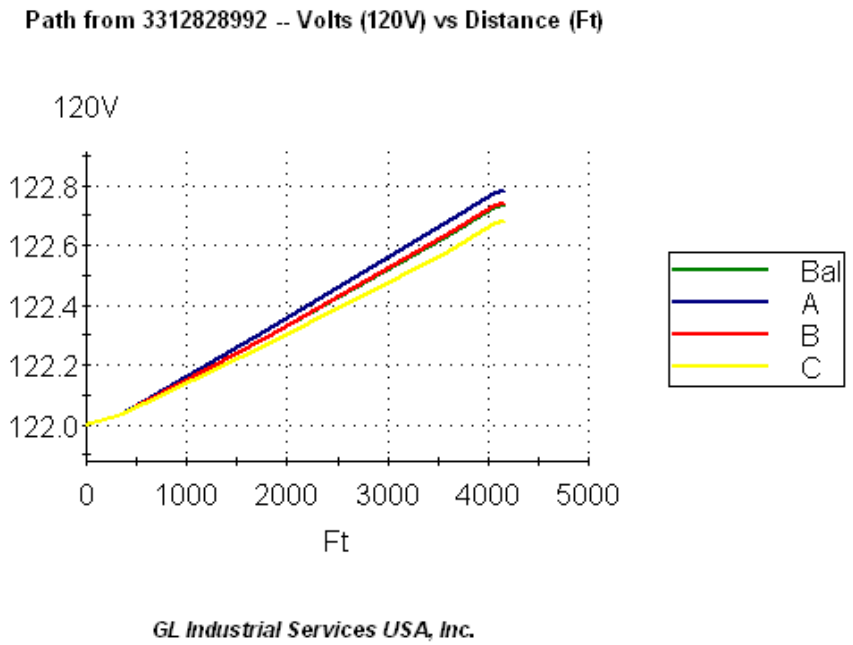
Graph 3 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for daylight hours minimum load on October 25, 2009. Project Los Morros is OFF.



The model voltages at the point of interconnection are:
Phase A – 122.0 volts Phase B – 122.0 volts Phase C – 121.9 volts Balanced – 122.0 Volts.

The voltages on Los Morros Feeder 21 prior to the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for daylight hours minimum load on October 25, 2009. Project Los Morros is ON, 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 122.8 volts Phase B – 122.7 volts Phase C – 122.7 volts Balanced – 122.7 volts.

The voltages on Los Morros Feeder 21 after the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4 Voltage impacts for maximum daylight hours load for contingency configuration

Presently, there are three possible scenarios for contingency configuration that Project Los Morros can contribute to. The first is for the loss of Los Morros Unit II Substation, the second is for the loss of Los Lunas Substation and the third is for the loss of Los Morros Unit I Substation.

Tables 5 – 7 show the load data used for the contingency evaluations. For 2009, Los Lunas Feeder 11 was carrying additional load from San Clemente Substation. Therefore, the 2009 maximum and minimum data for Los Lunas Feeder 11 could not be determined. Table 5 shows

the projected 2009 maximum and 2008 minimum daylight hours loading on Los Lunas Feeder 11.

Table 5 **– *Los Lunas Feeder 11 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 31,2008	5 PM	3,870	-719	3,936	-98.3	197	138	205
May 25, 2008	7 AM	1,171	-918	1,488	-78.7	71	59	76

Table 6 shows the maximum and minimum daylight hours loading on Los Morros Feeder 11.

Table 6 **– *Los Morros Feeder 11 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
May 14, 2009	7 PM	2,226	1,330	2,593	85.9	112	115	125
Dec. 25, 2009	10 AM	633	179	658	96.2	29	29	30

Table 7 shows the maximum and minimum daylight hours loading on Los Morros Feeder 12.

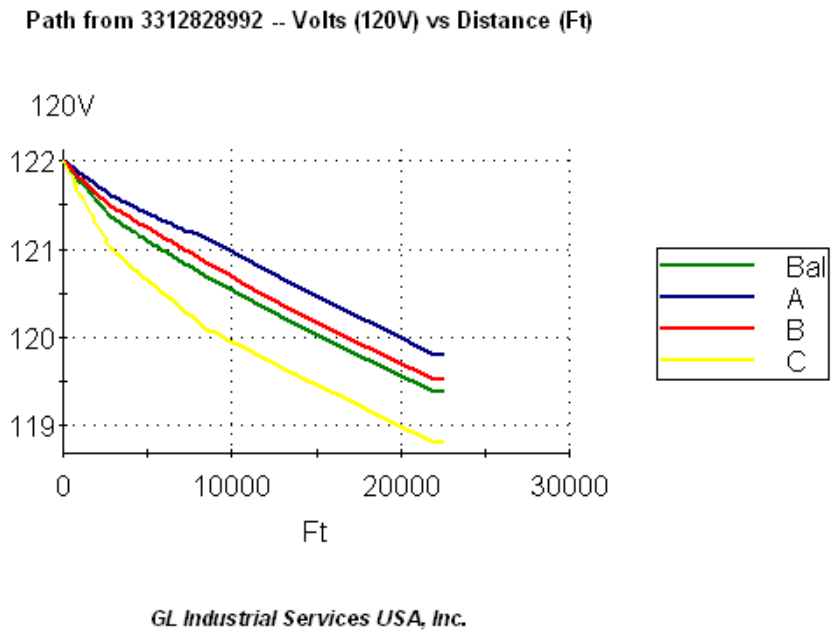
Table 7 **– *Los Morros Feeder 12 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 13,2009	7 PM	1,530	823	1,737	88.1	86	120	29
May 25, 2009	8 AM	380	169	416	91.3	23	25	9

4.4.1 Contingency configuration – Loss of Los Morros Unit II Substation, maximum load

For the loss of the Los Morros Unit II Substation, Los Morros Feeder 21 is transferred to Los Lunas Substation through Los Lunas Feeder 11. Voltage for the feeder daylight hours maximum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 5 and 6. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from Los Lunas Substation to the Project Los Morros point of interconnection (POI) is about 22,595 ft. or 4.3 miles.

Graph 5 - Los Lunas Feeder 11 voltage drop from Los Lunas Substation to the Project Los Morros POI for the loss of Los Morros Unit I Substation for daylight hours maximum load on July 16, 2009. Project Los Morros is OFF.

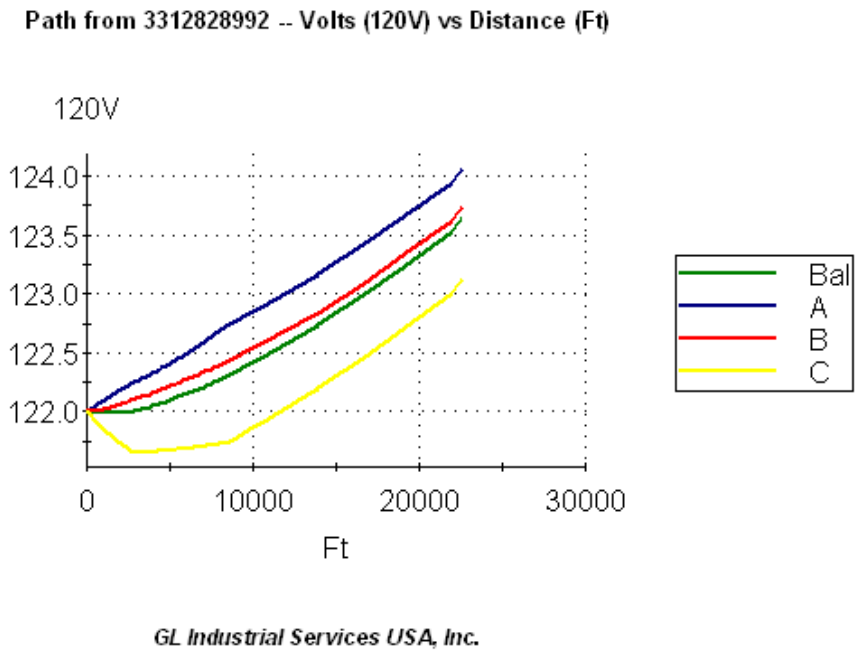


The model voltages at the point of interconnection are:

Phase A – 119.8 volts Phase B – 119.5 volts Phase C – 118.8 volts Balanced – 119.4 volts

The voltages on Los Lunas Feeder 11 for the loss of Los Morros Unit II Substation contingency prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 6 - Los Lunas Feeder 11 voltage drop from Los Lunas Substation to the Project Los Morros POI for the loss of Los Morros Unit I Substation for daylight hours maximum load on July 16, 2009. Project Los Morros is ON, at 100% power factor.



The model voltages at the point of interconnection are:

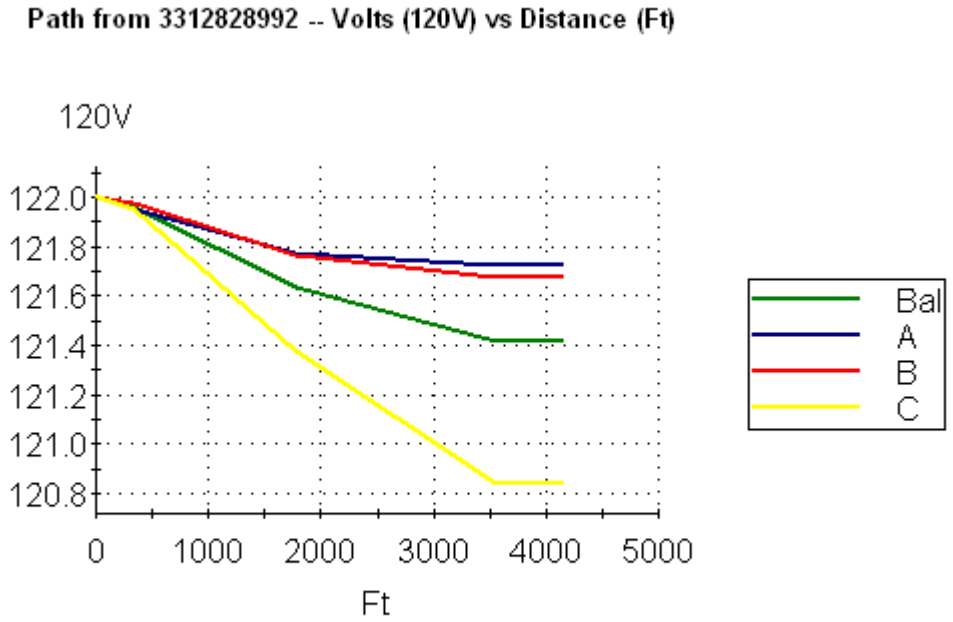
Phase A – 124.1 volts Phase B – 123.7 volts Phase C – 123.1 volts Balanced – 123.6 volts

The voltages on Los Lunas Feeder 11 for the loss of Los Morros Unit II Substation contingency after the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4.2 Contingency configuration – Loss of Los Lunas Substation, maximum load

For the loss of the Los Lunas Substation, 100% of Los Lunas Feeder 11 is transferred to Los Morros Feeder 21. Voltage for the feeder daylight hours maximum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 7 and 8. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from Los Morros Unit II Substation to the Project Los Morros POI is the same as was stated earlier for normal configuration.

Graph 7 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for the loss of Los Lunas Substation for daylight hours maximum load on July 16, 2009. Project Los Morros is OFF.



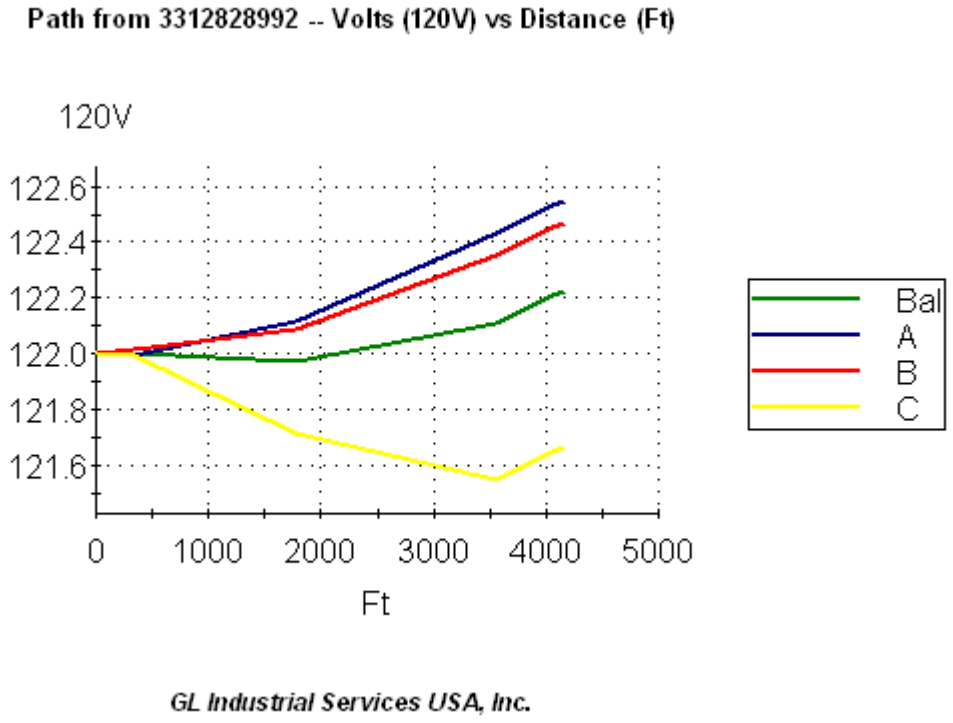
GL Industrial Services USA, Inc.

The model voltages at the point of interconnection are:

Phase A – 121.7 volts Phase B – 121.7 volts Phase C – 120.8 volts Balanced – 121.4 volts

The voltages on Los Morros Feeder 21 for the loss of Los Lunas Substation contingency prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 8 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for daylight hours maximum load on July 16, 2009. Project Los Morros is ON, at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 122.5 volts Phase B – 122.5 volts Phase C – 121.7 volts Balanced – 122.2 volts

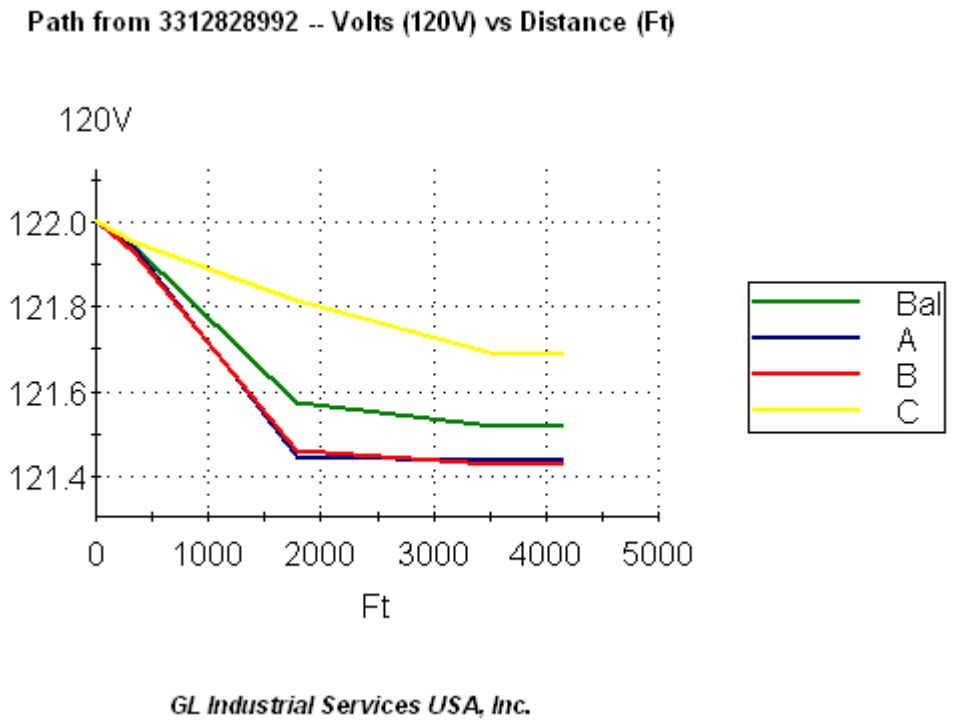
The voltages on Los Morros Feeder 21 for the loss of Los Morros Unit II Substation contingency after the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4.3 Contingency configuration – Loss of Los Morros Unit I Substation, maximum load

For the loss of the Los Morros Unit I Substation, 100% of Los Morros Feeder 11 and Los Morros Feeder 12 is transferred to Los Morros Feeder 21. Voltage for the feeder daylight hours maximum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 9 and 10. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours maximum date and time. The circuit

distance from Los Morros Unit II Substation to the Project Los Morros POI is the same as was stated earlier for normal configuration.

Graph 9 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for the Loss of Los Morros Unit I Substation for daylight hours maximum load on July 16, 2009. Project Los Morros is OFF.

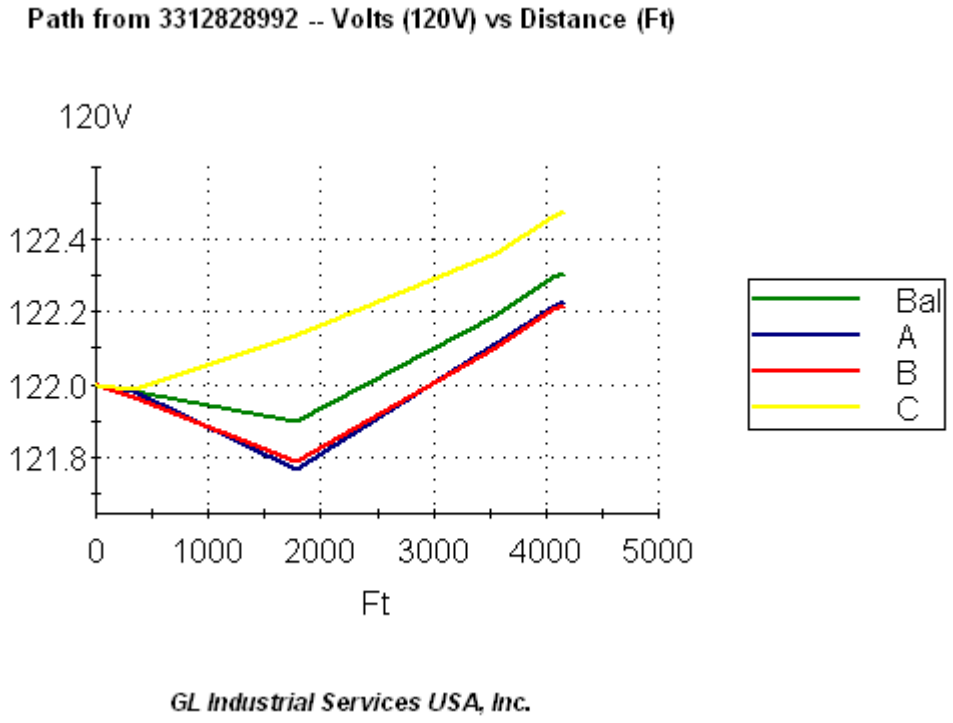


The model voltages at the point of interconnection are:

Phase A – 121.4 volts Phase B – 121.4 volts Phase C – 121.7 volts Balanced – 121.5 volts

The voltages on Los Morros Feeder 21 for the loss of Los Morros Unit I Substation contingency prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 10 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for the loss of Los Morros Unit I Substation for daylight hours maximum load on July 16, 2009. Project Los Morros is ON, at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 122.2 volts Phase B – 122.2 volts Phase C – 122.5 volts Balanced – 122.3 volts

The voltages on Los Morros Feeder 21 for the loss of Los Morros Unit II Substation contingency after the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

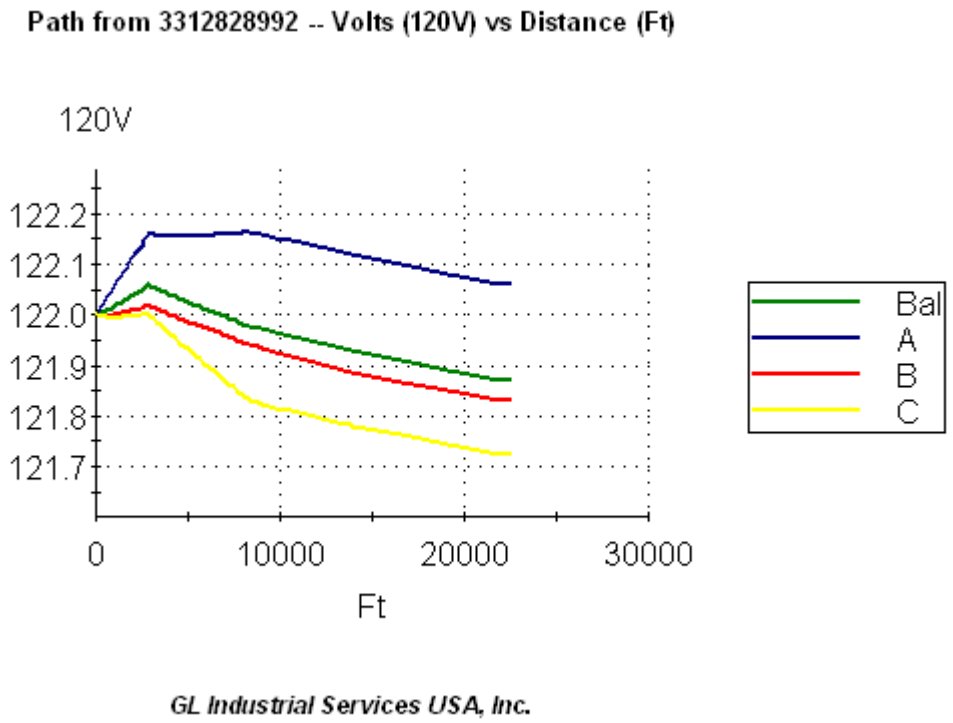
4.5 Voltage impacts for minimum daylight hours load for contingency configuration

4.5.1 Contingency configuration – Loss of Los Morros Unit II Substation, minimum load

For the loss of the Los Morros Unit II Substation, Los Morros Feeder 21 is transferred to Los Lunas Substation through Los Lunas Feeder 11. Voltage for the feeder daylight hours minimum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in

Graphs 11 and 12. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours minimum date and time.

Graph 11 - Los Lunas Feeder 11 voltage drop from Los Lunas Substation to the Project Los Morros POI for the loss of Los Morros Unit II Substation for daylight hours minimum load on October 25, 2009. Project Los Morros is OFF.

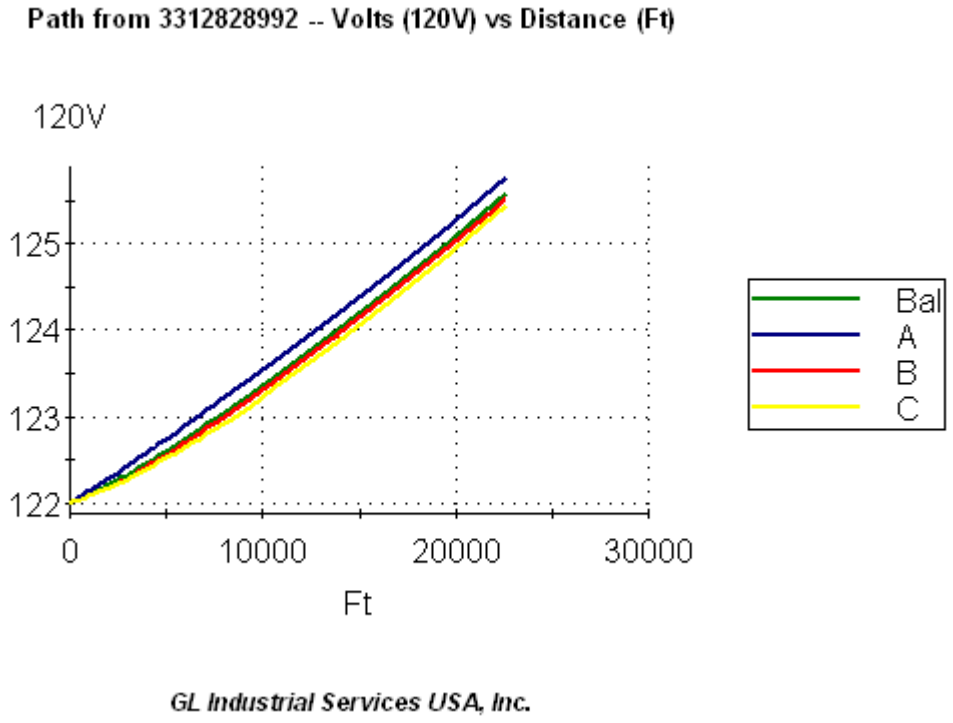


The model voltages at the point of interconnection are:

Phase A – 122.1 volts Phase B – 121.8 volts Phase C – 121.7 volts Balanced – 121.9 volts.

The voltages on Los Lunas Feeder 11 for the loss of Los Morros Unit II Substation contingency prior to the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 12 - Los Lunas Feeder 11 voltage drop from Los Lunas Substation to the Project Los Morros POI for the loss of Los Morros Unit II Substation for daylight hours minimum load on October 25, 2009. Project Los Morros is ON, at 100% power factor.



The model voltages at the point of interconnection are:

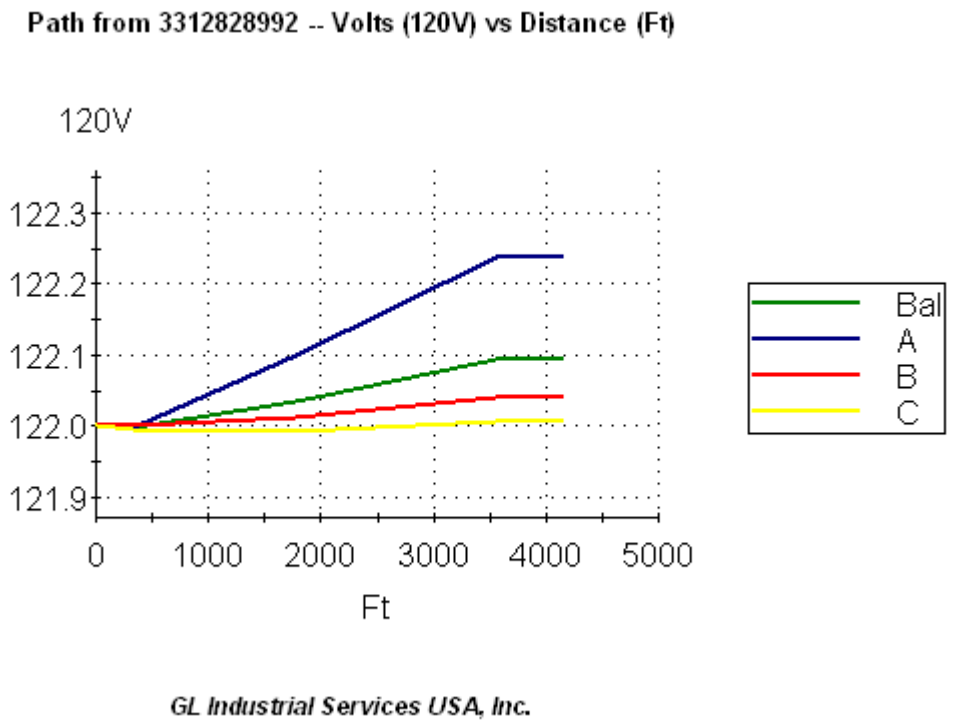
Phase A – 125.8 volts Phase B – 125.5 volts Phase C – 125.4 volts Balanced – 125.6 volts

The voltages on Los Lunas Feeder 11 for the loss of Los Morros Unit II Substation contingency after the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5.2 Contingency configuration – Loss of Los Lunas Substation, minimum load

For the loss of the Los Lunas Substation, 100% of Los Lunas Feeder 11 is transferred to Los Morros Feeder 21. Voltage for the feeder daylight hours minimum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 13 and 14. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours minimum date and time. The circuit distance from Los Morros Unit II Substation to the Project Los Morros POI is the same as was stated earlier for normal configuration.

Graph 13 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for the loss of Los Lunas Substation for daylight hours minimum load on October 25, 2009. Project Los Morros is OFF.

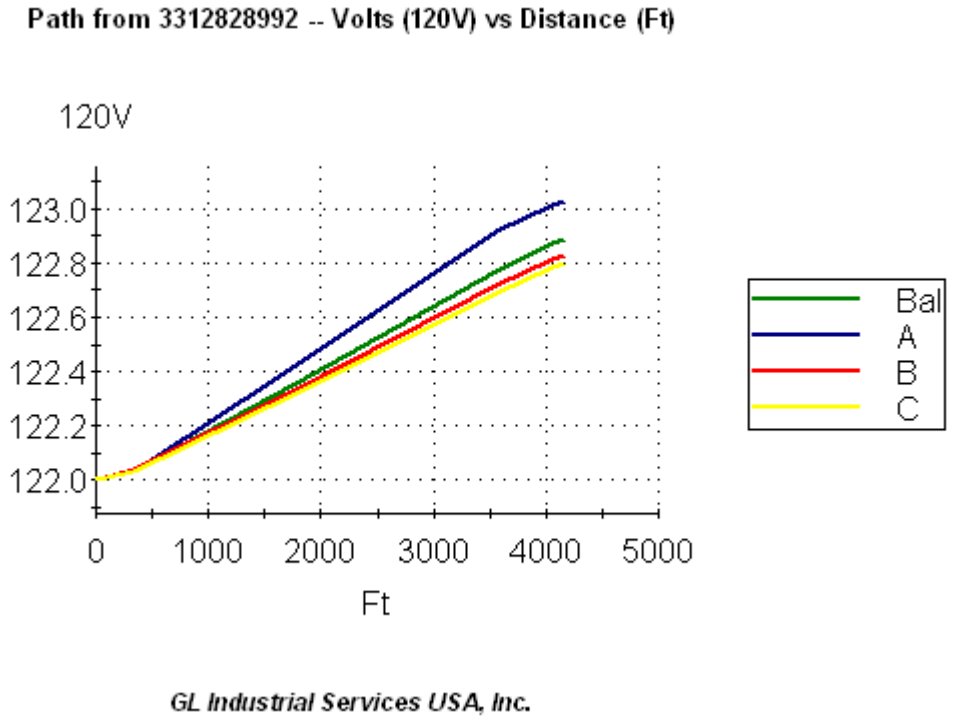


The model voltages at the point of interconnection are:

Phase A – 122.2 volts Phase B – 122.0 volts Phase C – 112.0 volts Balanced – 112.1 volts

The voltages on Los Morros Feeder 21 for the loss of Los Lunas Substation contingency prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 14 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for the loss of Los Lunas Substation for daylight hours minimum load on October 25, 2009. Project Los Morros is ON, at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.0volts Phase B – 122.8 volts Phase C – 122.8 volts Balanced – 122.9 volts

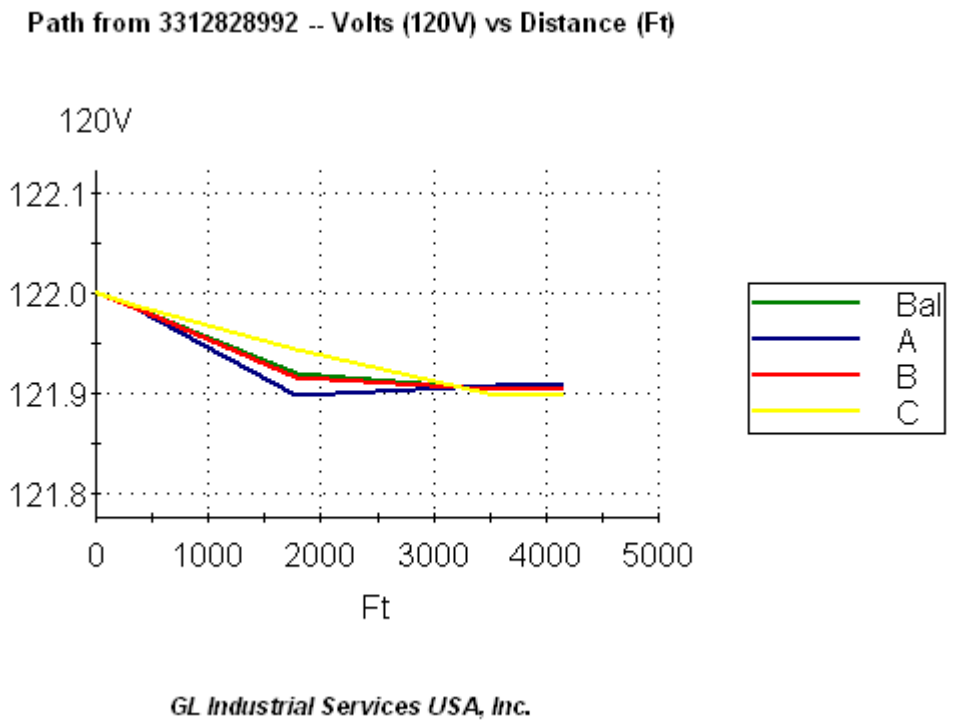
The voltages on Los Morros Feeder 21 for the loss of Los Lunas Substation contingency after the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5.3 Contingency configuration – Loss of Los Morros Unit I Substation, minimum load

For the loss of the Los Morros Unit I Substation, 100% of Los Morros Feeder 11 and Los Morros Feeder 12 is transferred to Los Morros Feeder 21. Voltage for the feeder daylight hours minimum load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 15 and 16. Larger customer loads on the feeder, including Merillat, were modeled using actual load values from the daylight hours minimum date and time. The circuit

distance from Los Morros Unit II Substation to the Project Los Morros POI is the same as was stated earlier for normal configuration.

Graph 15 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for the Loss of Los Morros Unit I Substation for daylight hours minimum load on October 25, 2009. Project Los Morros is OFF.

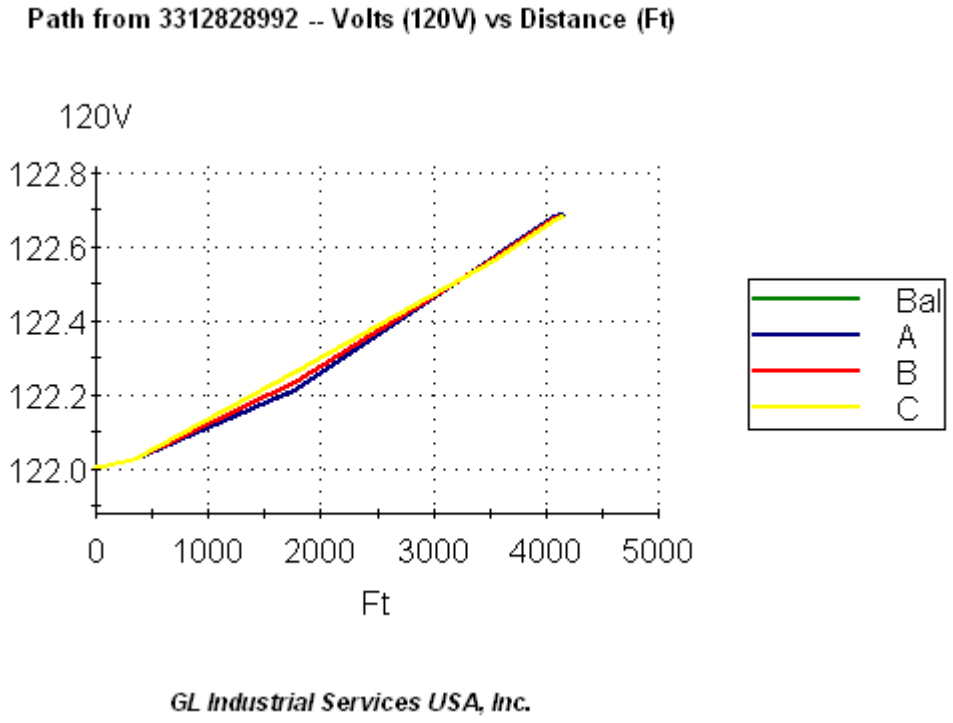


The model voltages at the point of interconnection are:

Phase A – 121.9 volts Phase B – 121.9 volts Phase C – 121.9 volts Balanced – 121.9 volts

The voltages on Los Morros Feeder 21 for the loss of Los Morros Unit I Substation contingency prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 16 - Los Morros Feeder 21 voltage drop from Los Morros Unit II Substation to the Project Los Morros POI for the loss of Los Morros Unit I Substation for daylight hours minimum load on October 25, 2009. Project Los Morros is ON, at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 122.7 volts Phase B – 122.7 volts Phase C – 122.7 volts Balanced – 122.7 volts

The voltages on Los Morros Feeder 21 for the loss of Los Morros Unit II Substation contingency after the installation of Project Los Morros are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion, Project Los Morros output does cause the voltage on Los Morros Feeder 21 and on Los Lunas Feeder 11 for contingency conditions to increase. However, the voltage stays within the PNM criteria of ANSI C84.1 and is acceptable.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Los Morros is served by Los Morros Feeder 21, and there is no voltage regulator installed on the feeder. The substation LTC is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 120.5 volts and will reduce the voltage if the substation bus is above 123.5 volts.

As seen in Tables 8 -11, the SynerGEE modeling shows the LTC did not change position for 6,000 KW source on the feeder for high or low load periods.

Project Los Morros was modeled as a source on Los Morros Unit II Substation connected to the end of Los Morros Feeder 21. The SynerGEE model included the substation transformer and Los Morros Feeders 21 and 23. The substation bus voltage and load tap changer position for maximum daylight hours load for 2009 with and without Project Los Morros 6MW, per the SynerGEE model, are shown in Tables 8 and 9.

Table 8 ***- Los Morros Unit II Substation with Project Los Morros OFF for daylight hours maximum load on July 16, 2009***

	LOS MORROS UNIT II SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.5	121.5	121.1	122.4
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 8. The voltages at Los Morros Unit II Substation prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 9 ***- Los Morros Unit II Substation with Project Los Morros ON, at 100% power factor for daylight hours maximum load on July 16, 2009***

	LOS MORROS UNIT II SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.8	121.8	121.4	121.6
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 9. The voltages at Los Morros Unit II Substation after the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The Los Morros Feeder 21 voltage for the feeder minimum daylight hours load for 2009 with and without Project Los Morros, per the SynerGEE model, are shown in Graphs 10 and 11.

Table 10 ***- Los Morros Unit II Substation with Project Los Morros OFF for daylight hours minimum load on October 25, 2009***

	LOS MORROS UNIT II SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.9	121.9	121.9	121.9
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 10. The voltages at Los Morros Unit II Substation prior to the installation of Project Los Morros are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 11 ***- Los Morros Unit II Substation with Project Los Morros ON, at 100% power factor for daylight hours minimum load on October 25, 2009***

	LOS MORROS UNIT II SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.1	121.1	121.1	121.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 11. The voltages at Los Morros Unit II Substation after the installation of Project Los Morros at 100% power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Los Morros Unit II Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of Project Los Morros output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid

change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Los Morros Unit II Substation bus was fixed at 122 volts with and without Project Los Morros output for maximum and minimum load periods. Table 10 summarizes the balanced voltage and the calculated voltage flicker. Table 13 is based on the GE flicker graph.

Table 12 ***- Voltage flicker at the POI due to Project Los Morros***

	Project Los Morros POI Bus Voltage	
	Minimum	**Maximum**
Without Project	122.0	121.7
With Project	122.7	122.5
% Voltage Flicker	**.57**	**.66**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 13 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
.57	1/minute	4/second
.66	30/hour	2/second

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 12 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 13. Results are less than the 6% criteria; therefore distribution voltage flicker resulting from changes in Project Los Morros output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Los Morros POI to the substation were reviewed using the SynerGEE feeder model with and without Project Los Morros's maximum output of 6,000 KW AC.

There were no conductor loading problems from the POI to the substation on Los Morros Feeder 21 with or without Project Los Morros.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. There are no capacitors on Los Morros Feeder 21 which serves Project Los Morros. Therefore, no capacitor bank switching occurs due to Project Los Morros.

Los Lunas Feeder 11 has two 1,200 KVAR RCCS capacitor banks. During the contingency analysis for the loss of Los Morros Unit II Substation, both capacitor banks were assumed to be on for the peak load timeframe based on historical load data. For minimum load timeframe, analysis was done for two situations; one with one 1200 KVAR on and the other with both capacitor banks off. For the contingency, with one 1200 KVAR RCCS capacitor bank on, and Project Los Morros at 100% of rated output, the voltage was marginally acceptable at 126.1 volts on one phase. With both capacitor banks off, the voltages are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. The remotely controlled capacitor banks on the feeder may potentially be de-energized, but this does not adversely impact voltages.

9.0 PROTECTION

9.1 Normal Configuration – Service from Los Morros Substation Feeder 21

Los Morros Substation feeder 21 is protected by a 1200 amp breaker in metal clad switchgear with three GE, DIAC IAC77 phase overcurrent relays and a DIAC IAC77 ground overcurrent relay. There is also a GE, SLR reclosing relay. The switchgear bus and feeder backup protection are three GE, DIAC IAC53 phase relays and a GE, DIAC IAC53 ground relay. The transformer protection is three GE, STD differential relays. The Los Morros Project PV system is connected to the system approximately 0.79 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder. However, fault current from the substation is reduced because of the contribution of the PV system. Portions of the feeder are exposed to delayed fault clearing.

The Los Morros Project does require system protection improvements to be made to the Los Morros Substation feeder 21 under normal configuration. Distribution Protection recommends installing one three phase Nova recloser on Los Morros 21 to eliminate exposures created by the interconnection of the PV system, Project Los Morros. By interconnecting this PV system to the Los Morros feeder, the overall fault current provided by the substation through the feeder relay is reduced, thus delaying the clearing time. This recloser will be installed in a location that will allow it to detect total available fault current from both sources allowing clearing times to meet PNM's standard protection criteria. The proposed location, shown in Figure 2, for the recloser is north of the intersection of Don Pasqual Road and Mesa Bonita Place. Figure 3 shows a street view of this location.

Figure 2 **– *Feeder view of proposed recloser location***

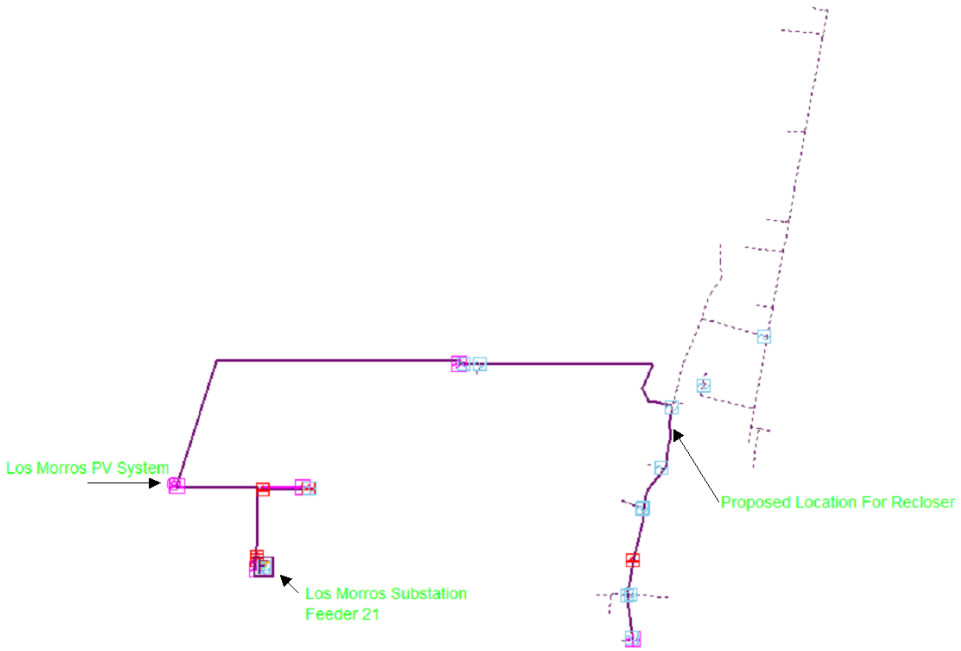
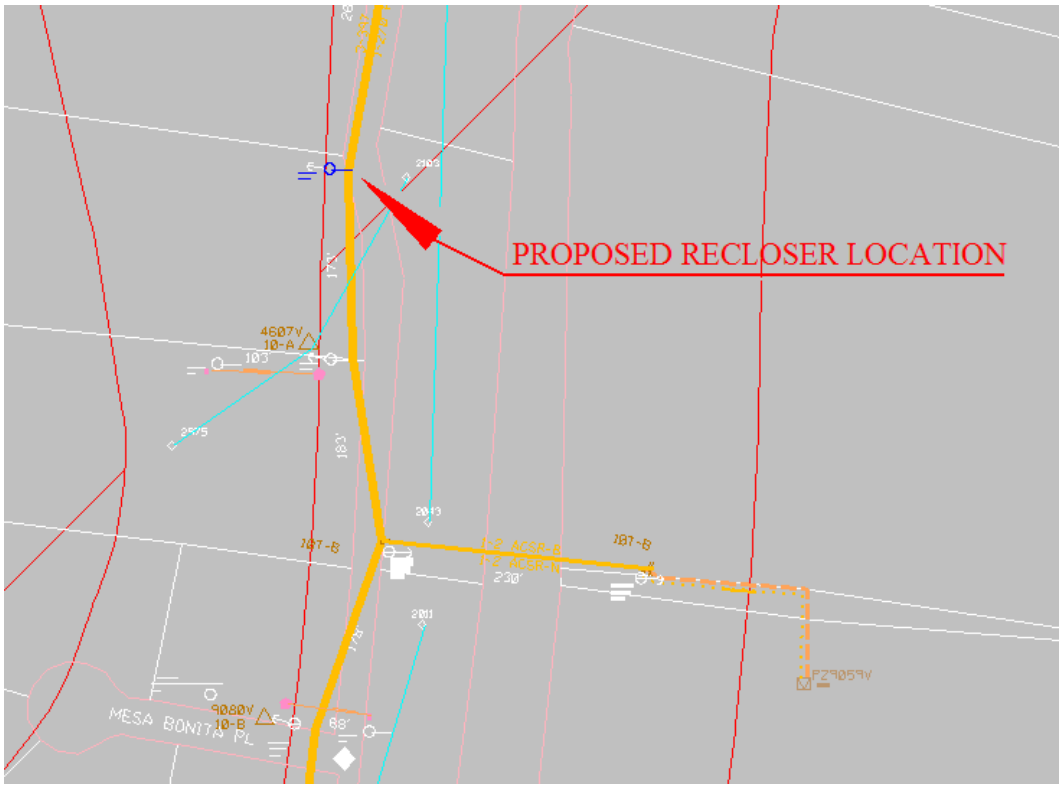


Figure 3 *– Street view of proposed recloser location*



9.2 Normal Feeder as a Backup Feeder – Los Morros Feeder 21 picks up Los Lunas Feeder 11, Los Morros Feeder 11 or Los Morros Feeder 12

Fault analysis of the system when Los Morros 21 is a backup feeder for Los Morros 11, Los Morros 12 and Los Lunas 11 was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder. However, fault current from the substation is reduced because of the contribution of the PV system. Portions of the feeder are exposed to delayed fault clearing.

The Los Morros Project does require system protection improvements to be made to the Los Morros Substation feeder 21 under normal feeder as a backup feeder. Distribution Protection recommends installing two three phase Nova recloser, one SCADA controlled, on Los Morros 21 to eliminate exposures created by the interconnection of the PV system, Project Los Morros. By interconnecting this PV system to the Los Morros feeder, the overall fault current provided by the substation through the feeder relay is reduced, thus delaying the clearing time. These reclosers will be installed in locations that will allow it them to detect total available fault current from both sources allowing clearing times to meet PNM's standard protection criteria. The proposed locations, shown in Figure 4, for the reclosers is one north of the intersection of Don Pasqual Road and Mesa Bonita Place and one along the I-25 Freeway near the Los Lunas Well. Figure 5 shows a street view of the one proposed north of the intersection of Don Pasqual Road and Mesa Bonita Place. Figure 6 shows the one along the I-25 Freeway near the Los Lunas Well.

Figure 4 *– Feeder view of proposed recloser locations*

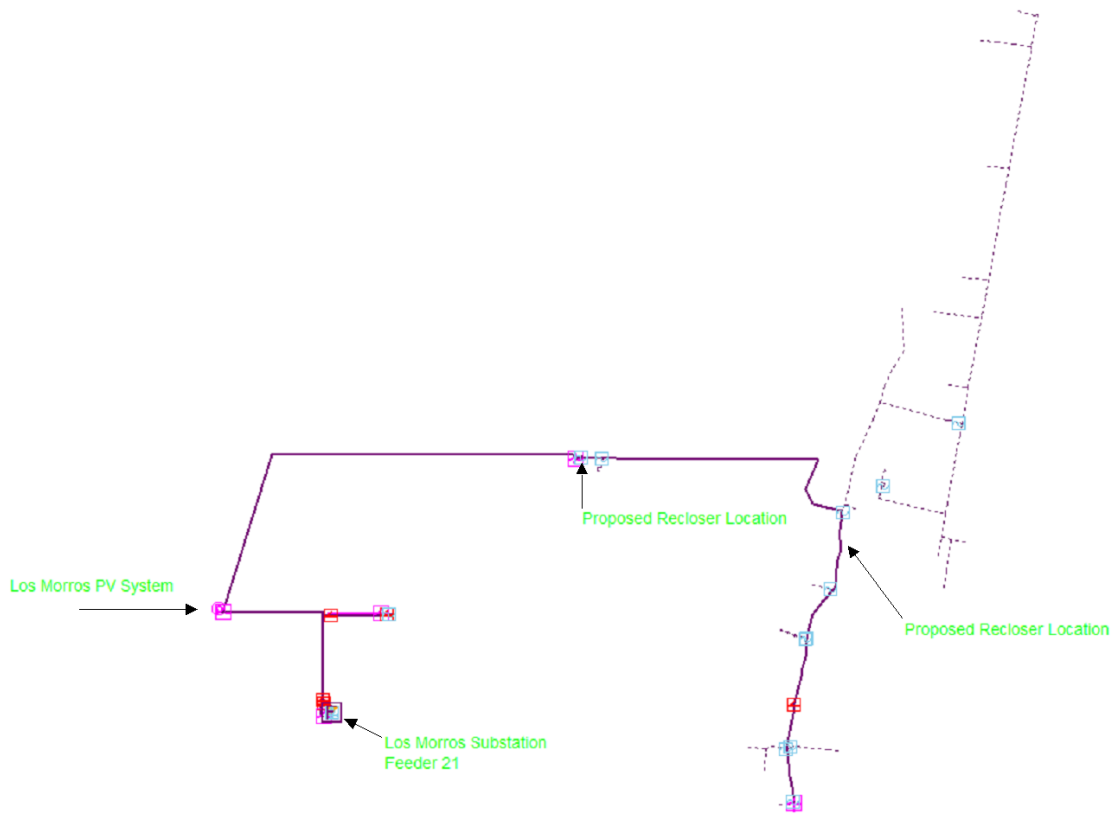


Figure 5 *– Street view of first reclosers proposed location*

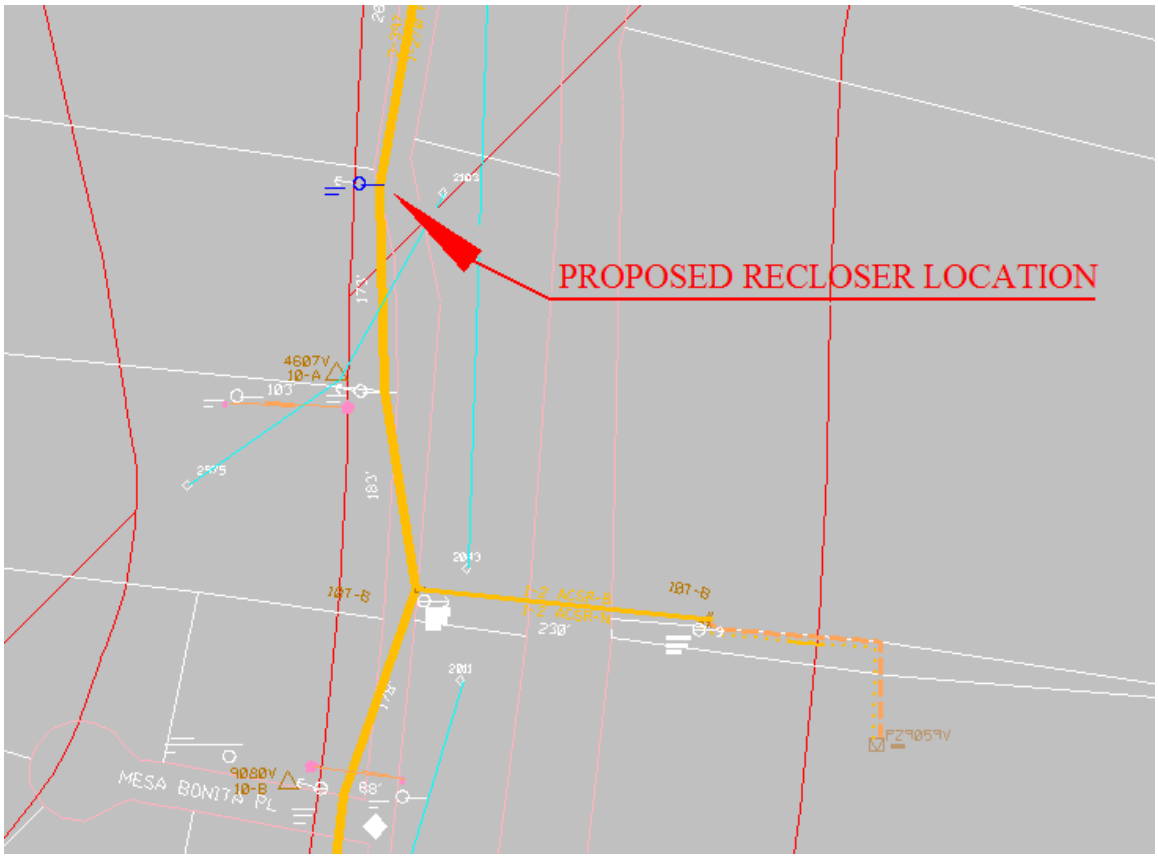
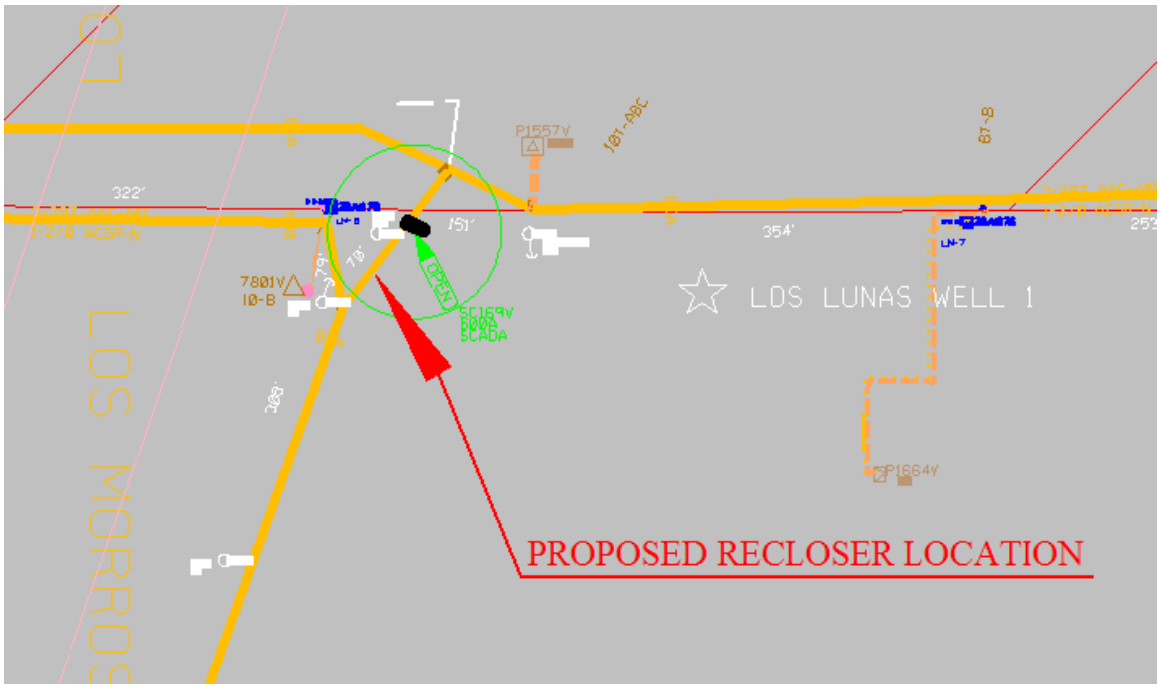


Figure 6 *– Street view of second reclosers proposed location*



9.3 Contingency Configuration – Los Lunas Feeder 11 picks up Los Morros Feeder 21

Los Lunas Substation feeder 11 is protected by a 1200 amp breaker in metal clad switchgear with three GE, IAC53 phase overcurrent relays and one GE, IAC53 ground overcurrent relay. There is also a GE, ACR reclose relay. The switchgear bus and feeder backup protection is three S&C, SMD-2C 150E Fuses. The Los Morros Project PV system will be connected to the system approximately 4.28 miles from the substation.

Fault analysis of the system for Los Lunas 11 was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder.

Project Los Morros does not require any system protection improvements to be made to the Los Lunas Substation feeder 11 under contingency configuration.

Distribution Protection recommends installing 2 – Three Phase Nova reclosers, one SCADA controlled for the addition of the Los Morros Project PV System. The total estimated cost is $90,000.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Los Morros output exceeds the 2009 minimum load on Los Morros Feeder 21 during daylight hours. No Los Morros Feeder 21 equipment overloads were identified.

Project Los Morros output exceeds the 2009 minimum load on Los Lunas Feeder 11 during daylight hours. No Los Lunas Feeder 11 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

The following cost estimates for communication have been developed:

ONE-TIME Equipment COST	$ 35,000
One-Time Labor Cost	$ 10,000
MONTHLY Recurring O&M	$ 3,500

The breakdown of the ONE-TIME Equipment cost:

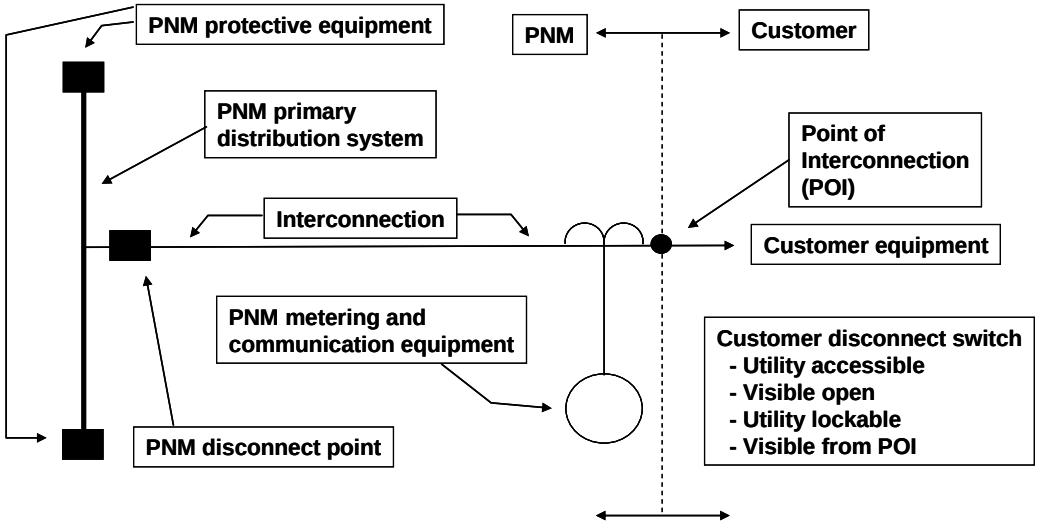
Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$ 20,000
Channel Bank Equipment	$ 10,000

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 7 is a one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 7 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



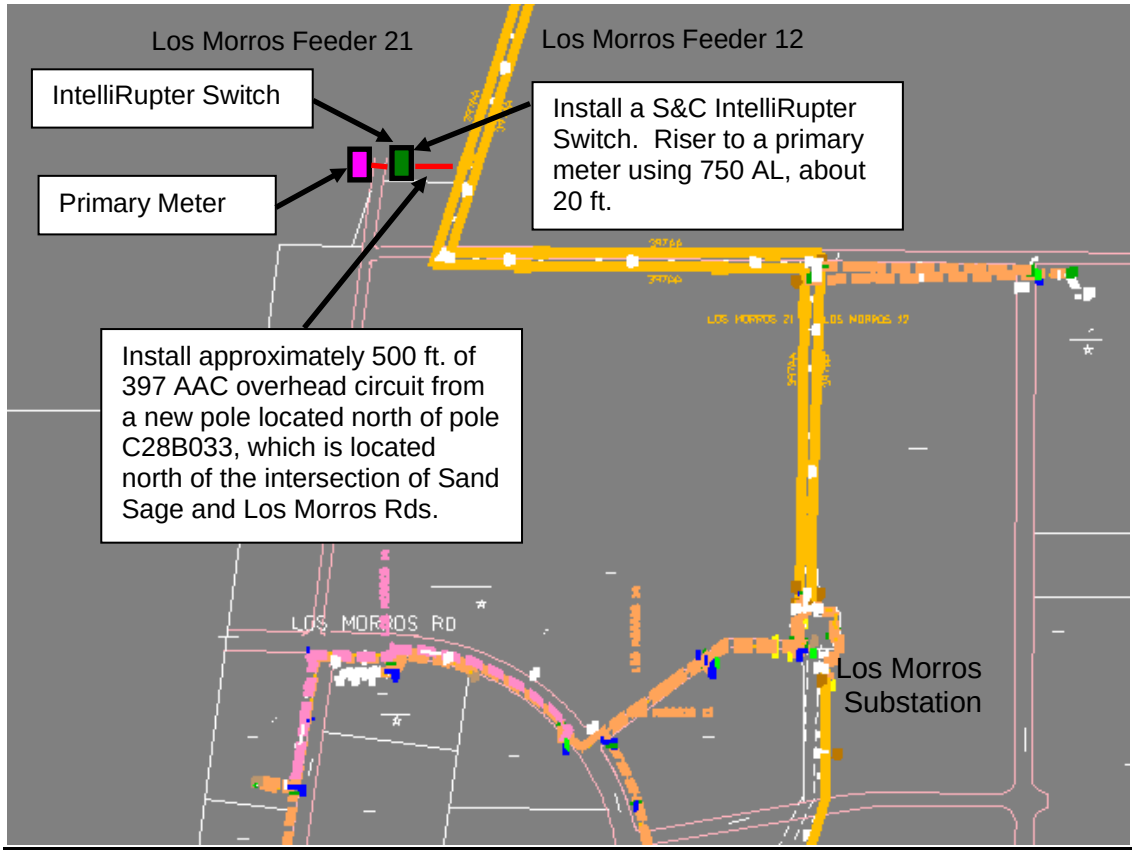
The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project Los Morros to the PNM distribution system, a line extension is required. The interconnection consists of:

- Install a new pole north of pole C28B033, and build approximately 500 ft. of new 397 AAC overhead circuit to the PV site location, which is located north of the intersection of Sand Sage and Los Morros Rds. (See Figure 8).
- Install one S&C IntelliRupter switch (See Figure 8).
- Install riser to primary meter, about 20 ft, using 750 AL (See Figure 8).

Figure 8 ***– Line Extension to connect Project Los Morros to Los Morros Feeder 21***



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 14.

Table 14 ***- Project Los Morros Interconnection Cost***

	ESTIMATED COSTS 2010$
PNM disconnect point (Intellirupter)	$ 51,000
Interconnection (Line Construction)	$ 68,300
PNM Primary metering	$ 24,500
Communications	$ 45,000
Protection	$ 90,000
TOTAL	**$ 278,800**

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This may also involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition is not expected to be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA).

16.0 CONCLUSIONS

Project Los Morros does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Los Morros Feeder 21. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. There are no remotely controlled capacitor banks on the feeder associated with Project Los Morros. The automatic control of voltage by the substation LTC may cause the LTC to operate, but this is not anticipated to be an adverse effect. The Project output will cause a flow of electricity from the distribution system through the substation transformer, the difference is approximately 5 MW, therefore no transmission voltage issues are anticipated. Analysis showed that the Project output did not cause conductor ratings to be exceeded. Finally, analysis shows that Project Los Morros output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Los Morros and has determined that there are no adverse impacts associated with a

6,000 KW AC source connected to Los Morros Unit II Substation connected to Los Morros Feeder 21.

Distribution Planning has determined that system upgrades are required to ensure that electric service to all customers on Los Morros Unit II Substation is maintained within established PNM voltage, equipment and fault protection criteria.

Project Alamogordo Airport
6 MW PV Generation Project

Small Generator Interconnection System Impact Study

(IA-PNM-2010-09)

October 2010

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution Planning and Contracts

Electric
Transmission

Foreword

This report was prepared for Public Service Company of New Mexico Generation Planning and Development department by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts department.

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EXECUTIVE SUMMARY

The proposed location for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 6,000 kW AC to the Public Service of New Mexico ("PNM") distribution primary system is in Alamogordo, New Mexico at 2274 U.S. 54, approximately one mile south of U.S. 70. The request is identified as Project Alamogordo Airport and would be connected to Alamogordo South Feeder 12-83. An application was submitted based on the PNM large PV program.

The estimated cost of connecting Project Alamogordo Airport to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRupter)	$ 52,800	~16 week lead time ~3 days construction
Interconnection (Line Construction)	$ 176,000	~16 week lead time ~8.5 weeks construction
System Upgrades	$ 283,019	~16 week lead time ~8.5 weeks construction
PNM Primary Metering	$ 19,400	~3 week lead time ~4 days construction
Protection	$ 5,000	~16 week lead time ~3 days construction
Communications	$ 45,000	~16 week lead time ~3 weeks construction
TOTAL	**$ 581,219**	

The application notes the use of twelve SMA Sunny Central 500HE 509 kW inverters, which are presently not certified UL 1741 compliant inverters. The SMA Sunny Central 500HE inverter will have a 1000V DC rating and is designed to meet UL 1741 compliance standards. Since UL testing is limited to 600V systems the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer technical data notes the inverter is capable of maintaining a unity power factor but also has the capability to control the reactive power to support voltage control. Due to voltage control issues identified in this report, voltage regulation will be required, which precludes the use of a UL 1741 compliant inverter. Distribution Planning

recommends the use of a UL listed 1741 compliant inverter to insure, among other concerns, that the unit will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other various requirements as called out in the SGIP application, Attachment 3. A complete field checkout of non-complaint equipment at the proposed facility is recommended before the facility can be considered certified for interconnection operation.

This System Impact Study ("Study) evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic ("PV") generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Alamogordo Airport does have an adverse impact on the PNM distribution system when operating at 100% power factor ("PF") output. The following results show how utilizing a PF output of 99% lagging eliminates the adverse impacts of the PV system. Project Alamogordo Airport would still be producing 5940 kW. Approximately 846 kVAr would need to be imported by the PV system.

The Project location will result in an interconnection with Alamogordo South Feeder 12-83 and analysis results with the inverter operating at 99% PF lagging were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud cover will not cause voltage flicker irritation problems.
4. Project output does cause conductors ratings to be exceeded; necessary reconductor is included in the interconnection cost.
5. The Project contribution to fault current does not adversely impact the protection coordination on Alamogordo South Feeder 12-83. However the available fault current from the PV system may be higher than the ground pickup on the feeder relay.

6. Project output will cause a flow of electricity from the distribution system through the substation transformer, but is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Alamogordo Airport and has determined that there are no adverse impacts associated with a 6,000 kVA AC source connected to Alamogordo South Feeder 12-83 when operated at a fixed, lagging 99% power factor (5,940 kW + 846 kVAr).

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Alamogordo South Feeder 12-83 is maintained within established PNM voltage, equipment and fault protection criteria.

1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a photovoltaic ("PV") electric generation source connected to the distribution primary system identified as Project Alamogordo Airport. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Alamogordo Airport proposes to connect a 6,000 KW AC PV facility to Alamogordo South Substation Feeder 12-83 in Alamogordo, NM. The Project will be located on the west side of US Highway 54 approximately 1.4 miles south of US Highway 70, just east of the Alamogordo Airport, as shown in Figure 1. The circuit distance from Alamogordo South Substation to the Project Alamogordo Airport point of interconnection ("POI") is about 27,525 ft. or 5.21 miles.

Figure 1 ***– Project Alamogordo Airport Location***

3.0 SYSTEM CONFIGURATION

Project Alamogordo Airport is connected to Alamogordo South Feeder 12-83 served from Alamogordo South Substation. Table 1 shows the rating of Alamogordo South Substation as determined by manufacturer nameplate data.

Table 1 ***- Substation transformer nameplate rating***

Substation	Nameplate MVA Rating	Voltage Rating
Alamogordo SO	46.7	115-12.47

Table 2 shows the 2010 non-coincident peak summer loads for Alamogordo South Substation and feeders.

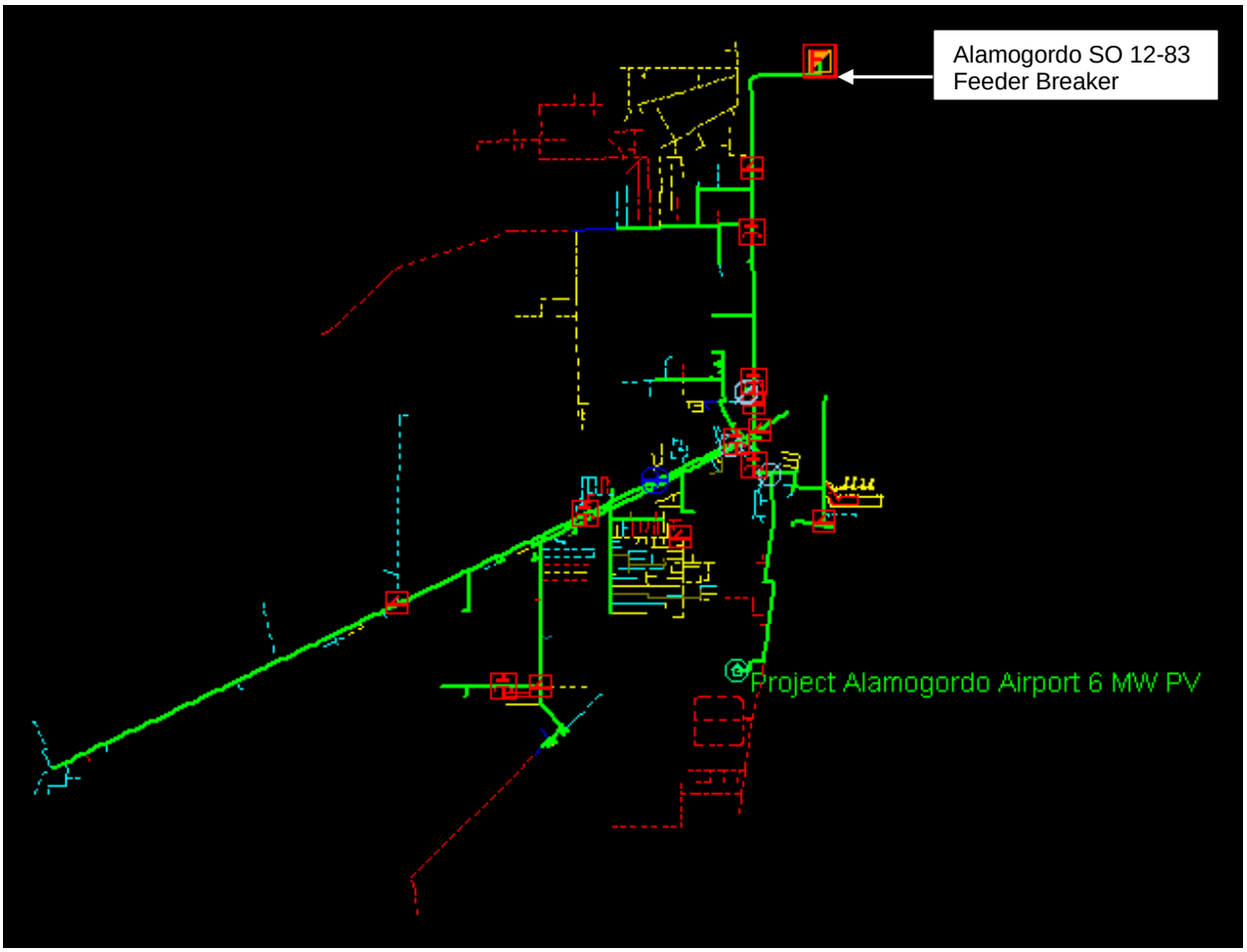
Table 2 ***- July 2010 Non-coincident Peak Loads***

Feeder	July 2010 Non-coincident Peak Load			
	KW	KVAr	KVA	% Power Factor
Alamogordo SO				
Fdr 12-83	7,582*	-446*	7,595*	-99.8*
Fdr 12-89	13,621*	2,897*	13,926*	97.8*
Alamo. SO Sub	21,245	1,162	21,276	99.9

* - Only individual feeder Amps available, kW/kVAr/kVA/pf estimated using historical data and capacitor bank consideration.

Figure 2 is a picture of the distribution feeder used in the Advantica SynerGEE modeling program.

Figure 2 ***– SynerGEE model of Alamogordo South Feeder 12-83***



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading for the period August 1, 2009 through July 31, 2010 on the Alamogordo South Feeder 12-83 are shown in Table 3:

Table 3 - ***Alamogordo South Feeder 12-83 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
June 5, 2010	5 PM	7,596	-478	7,611	-99.8%	320	328	375
Oct 4, 2009	7 AM	2,031	368	2,064	98.4%	88	91	96

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Alamogordo Airport at maximum output exceeds the load on Alamogordo South Feeder 12-83 at minimum daylight load timeframes. Therefore, Project Alamogordo Airport will cause a flow of power into Alamogordo South Substation. Table 4 shows the maximum and minimum daylight hours loading on the Alamogordo South Substation transformer for the period August 1, 2009 through July 31, 2010.

Table 4 - ***Alamogordo South Substation max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 14, 2010	5:00 PM	21,026	999	21,050	99.9	1,031	985	1,006
April 18, 2010	7:00 AM	5,827	-1,419	5,997	-97.2	245	248	259

The minimum daylight load on the Alamogordo South Substation transformer, as shown in Table 4, is slightly less than the rated output of Project Alamogordo Airport. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system.

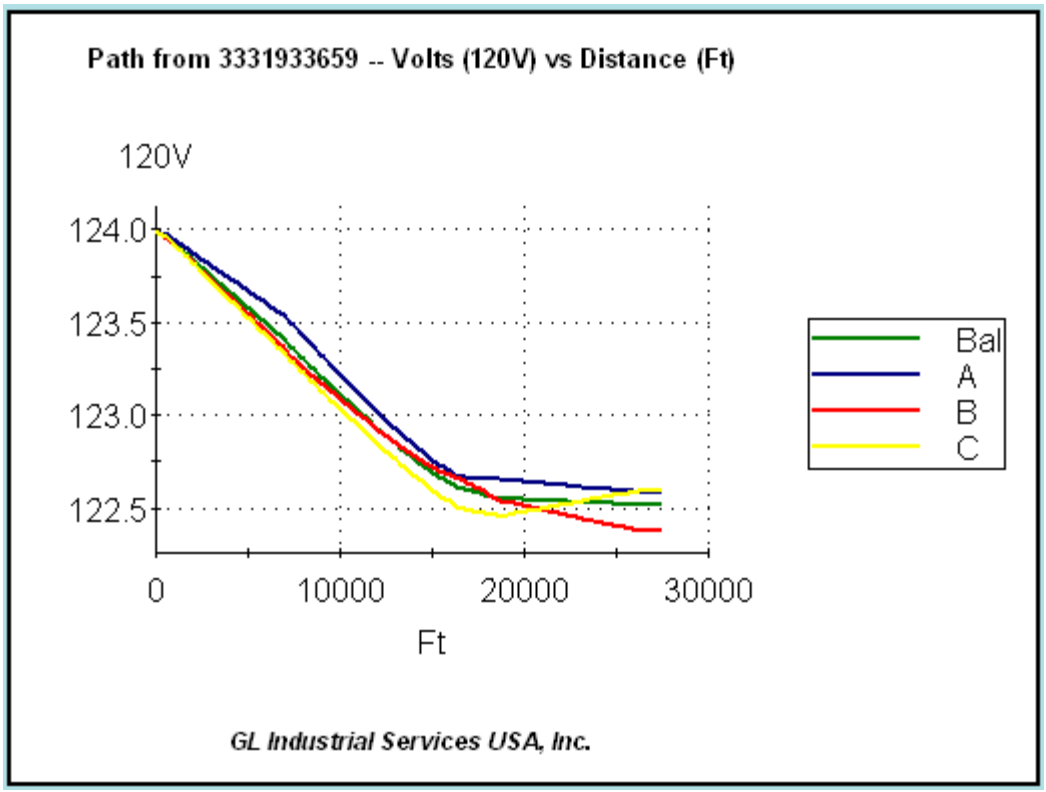
4.1 Voltage impacts on the transmission system

Although the minimum daylight load on the Alamogordo South Substation transformer is less than the rated output of the project, the difference is less than 5 MW; therefore no transmission related issues are anticipated to be associated with Project Alamogordo Airport.

4.2 Voltage impacts for minimum daylight hours load

The Alamogordo South Feeder 12-83 voltage for the feeder minimum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport, per the SynerGEE model, are shown in Graphs 1, 2, and 3.

Graph 1 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI without Project Alamogordo Airport for daylight hours minimum load on October 4, 2009

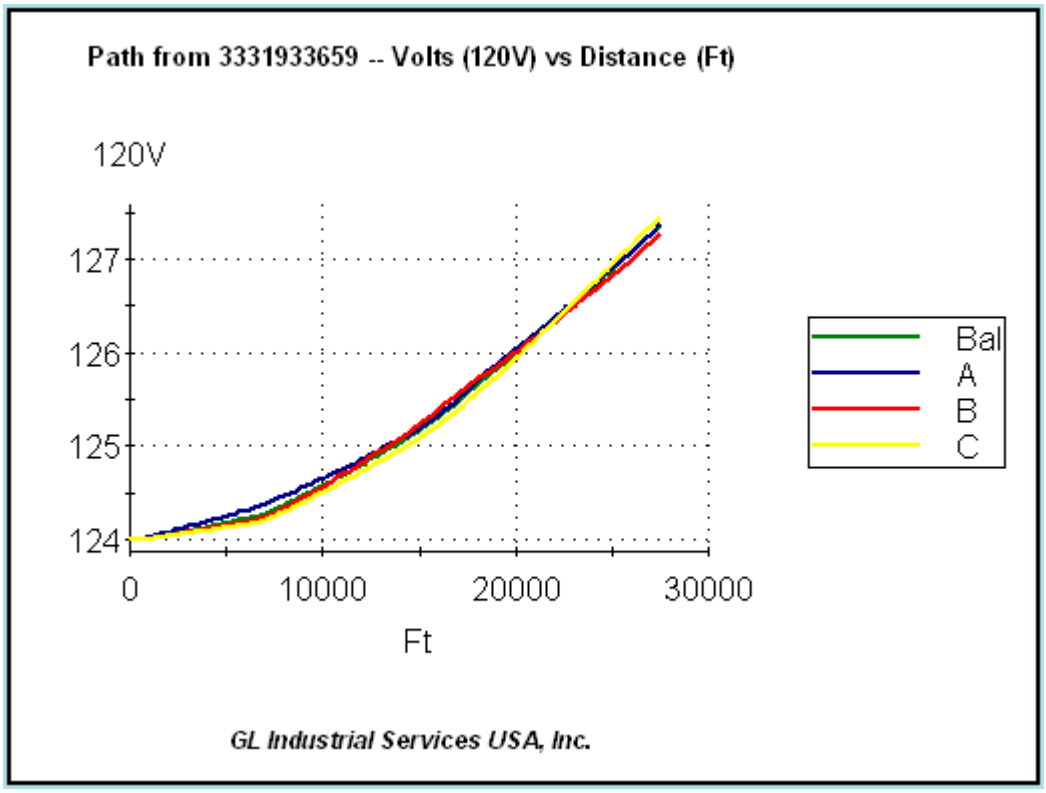


The model voltages at the point of interconnection are:

Phase A – 122.6 volts Phase B – 122.4 volts Phase C – 122.6 volts Balanced – 122.5 volts

The voltages on Alamogordo South Feeder 12-83 prior to the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on only fixed capacitor bank 1382279 (600 kVAr) being on.

Graph 2 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours minimum load on October 4, 2009, 100% PF output

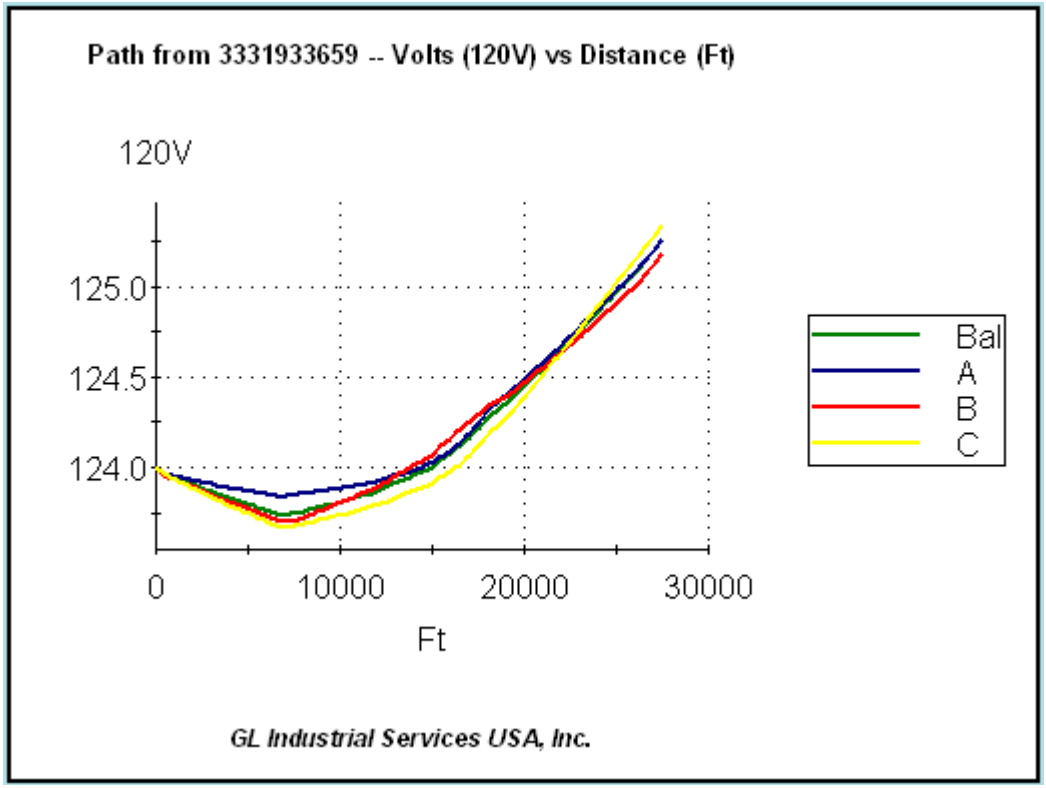


The model voltages at the point of interconnection are:

Phase A – 127.4 volts Phase B – 127.3 volts Phase C – 127.5 volts Balanced – 127.4 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 100% PF output, are outside the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. This model is based on only fixed capacitor bank 1382279 (600 kVAr) being on.

Graph 3 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours minimum load on October 4, 2009, 99% lagging PF output



The model voltages at the point of interconnection are:

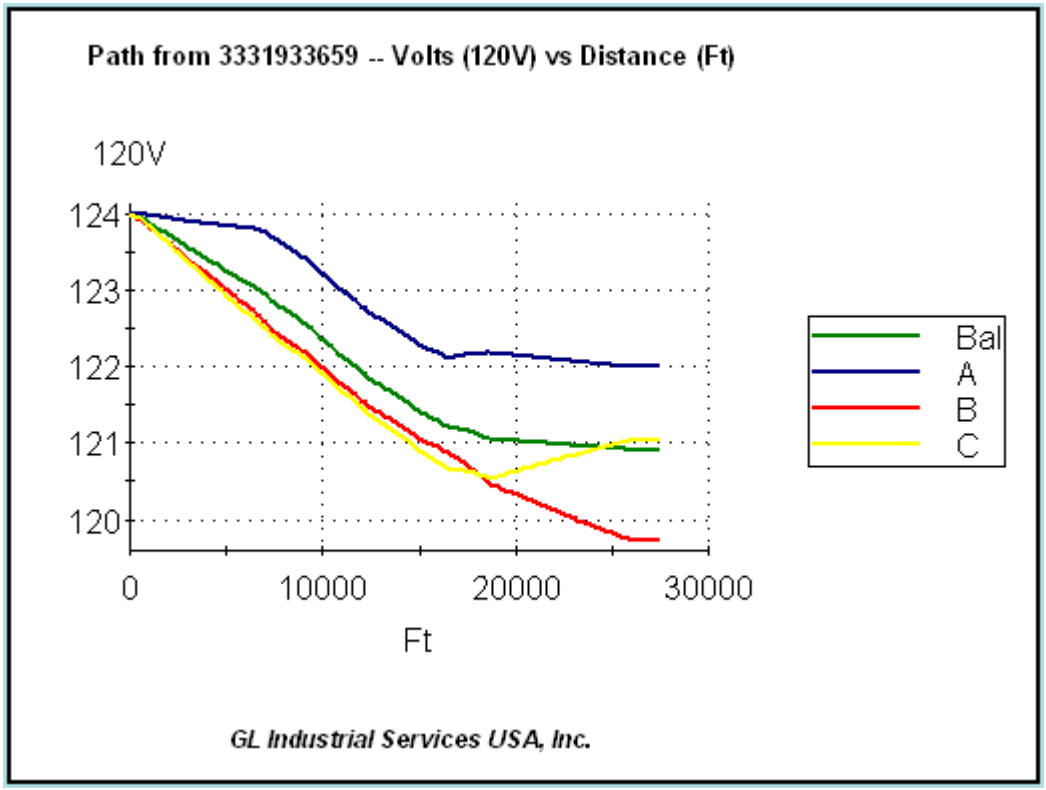
Phase A – 125.3 volts Phase B – 125.2 volts Phase C – 125.3 volts Balanced – 125.3 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 99% lagging PF output, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on only fixed capacitor bank 1382279 (600 kVAr) being on.

4.3 Voltage impacts for maximum daylight hours load

The Alamogordo South Feeder 12-83 voltage for the feeder maximum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport, per the SynerGEE model, are shown in Graphs 4, 5, and 6.

Graph 4 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI without Project Alamogordo Airport for daylight hours maximum load on June 5, 2010

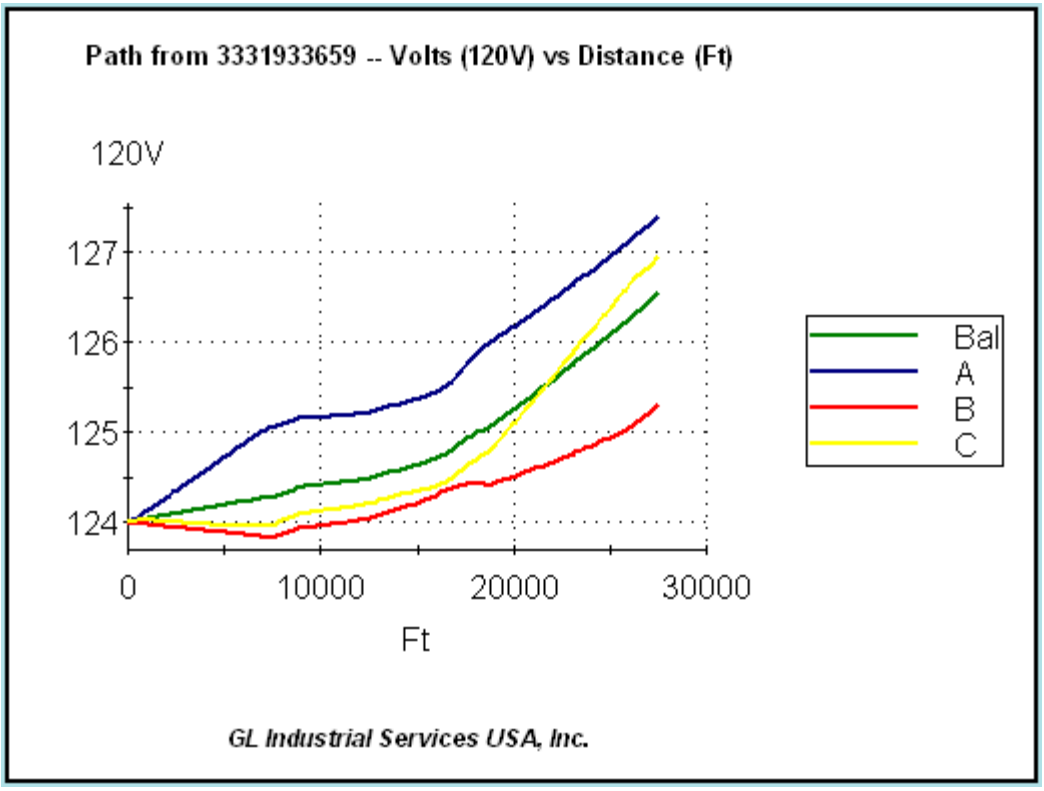


The model voltages at the point of interconnection are:

Phase A – 122.0 volts Phase B – 119.7 volts Phase C – 121.0 volts Balanced – 120.9 volts

The voltages on Alamogordo South Feeder 12-83 prior to the installation of Project Alamogordo Airport are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on all capacitor banks on Alamogordo South Feeder 12-83 (4200 kVAr total) energized.

Graph 5 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours maximum load on June 5, 2010, 100% PF output

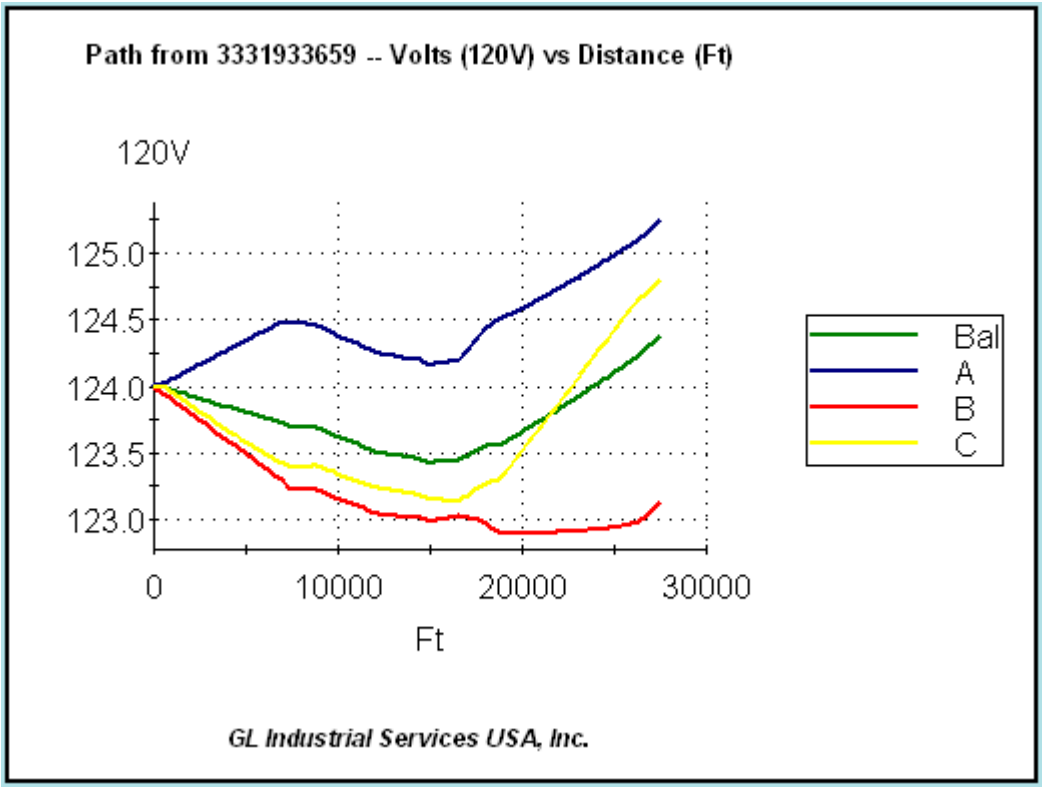


The model voltages at the point of interconnection are:

Phase A –127.4 volts Phase B – 125.3 volts Phase C – 127.0 volts Balanced – 126.6 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 100% PF output, are outside the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. This model is based on all capacitor banks on Alamogordo South Feeder 12-83 (4200 kVAr total) energized.

Graph 6 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours maximum load on June 5, 2010, 99% lagging PF output



The model voltages at the point of interconnection are:

Phase A –125.2 volts Phase B – 123.1 volts Phase C – 124.8 volts Balanced – 124.4 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 99% lagging PF output, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on all capacitor banks on Alamogordo South Feeder 12-83 (4200 kVAr total) energized.

In conclusion, Project Alamogordo Airport output does cause the voltage on Alamogordo South Feeder 12-83 to increase to unacceptable levels when allowed to operate at 100% PF. Operating at 99% lagging PF allows the voltage to stay within the PNM criteria of ANSI C84.1 and is acceptable.

Review under contingency transfer was not conducted since feeder Alamogordo South 12-83, under any pertinent contingencies, is simply transferred using the substation bus tie breaker and therefore not necessary.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer ("LTC") of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Alamogordo South Feeder 12-83 has a voltage regulator installed on the feeder, but it is downstream from Project Alamogordo Airport. The substation LTC is set at 124 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 122.5 volts and will reduce the voltage if the substation bus is above 125.5 volts.

As seen in Tables 5-8, the SynerGEE modeling shows the LTC did not change position for a 6,000 kW source on the feeder for high or low load periods. This is not considered an adverse impact.

Project Alamogordo Airport was modeled as a source on Alamogordo South Substation connected to the end of Alamogordo South Feeder 12-83. The SynerGEE model included the substation transformer and Alamogordo South Feeders 12-83 and 12-89. The substation bus voltage and load tap changer position for maximum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport 6 MW, at a 99% lagging PF operation, per the SynerGEE model, are shown in Tables 5 and 6.

***Table 5* – Alamogordo South Substation with Project Alamogordo Airport OFF for daylight hours maximum load on July 14, 2010**

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.2	124.1	124.1
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 5. The voltages at Alamogordo South Substation prior to the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 6 ***– Alamogordo South Substation with Project Alamogordo Airport ON at 99% lagging PF for daylight hours maximum load on July 14, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.2	124.3	124.3	124.3
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 6. The voltages at Alamogordo South Substation after the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The substation bus voltage and load tap changer position for minimum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport 6 MW, at a 99% lagging PF operation, per the SynerGEE model, are shown in Tables 7 and 8.

Table 7 ***– Alamogordo South Substation with Project Alamogordo Airport OFF for daylight hours minimum load on April 18, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.1	124.1	124.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 7. The voltages at Alamogordo South Substation prior to the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8 ***– Alamogordo South Substation with Project Alamogordo Airport ON at 99% lagging PF for daylight hours minimum load on April 18, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.1	124.1	124.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 6. The voltages at Alamogordo South Substation after the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Alamogordo South Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of Project Alamogordo Airport output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company ("GE") developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a

distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Alamogordo Airport POI is shown in Section 4.0. Table 9 summarizes the voltage and the calculated voltage flicker for the worst case phase. Table 10 is based on the GE flicker graph.

Table 9 ***- Voltage flicker on Alamogordo South Feeder 12-83 due to Project Alamogordo Airport at -99% PF Output***

	POI Voltage Alamogordo South Feeder 12-83 Loading	
	Minimum (B-Phase)	**Maximum (C-Phase)**
Without Project	122.4	121.0
With Project	125.2	124.8
% Voltage Flicker	**2.29**	**3.14**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 10 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
2.29 (Min)	1.5/hour	26/hour
3.14 (Max)	Always Visible	10/hour

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 9 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 10. Distribution voltage flicker resulting from changes in Project Alamogordo Airport output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Alamogordo Airport POI to the substation were reviewed using the SynerGEE feeder model with and without Project Alamogordo Airport's maximum output of 6,000 kW AC.

There were no conductor loading problems from the POI to the substation on Alamogordo South Feeder 12-83 with Project Alamogordo Airport OFF. However, with Project Alamogordo Airport at maximum output, there were conductor loading problems. The estimate includes necessary line upgrade to 397 AAC conductor.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system in Alamogordo are controlled by a time setting, temperature setting, or voltage setting. These settings vary from bank to bank in this area.

An inverter based grid connection will be a real power source (Watts only, no VArs) for the distribution system when operated at 100% PF. For this Study, Project Alamogordo Airport was found to cause adverse impacts on the system for a 100% PF operation, so operation of 99% lagging PF is necessary. Regardless, when the inverter is operating and injecting watts, the power factor of the distribution feeder will appear to become worse.

Alamogordo South Feeder 12-83 has 4,200 total kVAr in capacitor banks (5x600 kVAr and 1x1200 kVAr). The June 2010 peak load on the feeder was estimated at 7,596 kW – j 478 kVAr or 7,611 kVA at a 99.8% leading power factor (i.e. 100.2% power factor). All capacitors were energized. Project Alamogordo Airport at a 5,940 kW + 846 kVAr AC output would change the

apparent feeder loading to 1,656 kW + j 368 kVAr or 1,696 kVA at a 97.6% lagging power factor.

Project Alamogordo Airport may cause a PF as low as 97.6% lagging on Alamogordo South Feeder 12-83, but no voltage issues were identified and the resulting new power factor would be acceptable.

9.0 PROTECTION

Alamogordo South Substation feeder 12-83 is protected by a 1200 Amp free standing breaker with three Westinghouse, CO-9 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO phase relays and one Westinghouse, CO residual ground relay. The transformer protection is three Westinghouse, HU-1 differential relays. The Alamogordo Airport Project PV system will be connected to the system approximately 5.21 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 Amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The Study first looked at the impact to a new three-phase Nova recloser. The available fault current at the recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder; however the available fault current from the PV system is higher than the ground pickup on the feeder relay. The unit sub protection scheme will need to be modified to trip and lockout the feeder breakers 12-67, 12-83, 12-89 and 12-7 for a bus fault where the backup ground relay protecting the bus operates.

Project Alamogordo Airport requires a system protection improvement to be made to the Alamogordo South Substation feeder 12-83. Recloser R12327A will be replaced, due to distribution protections' recommendation, with a three phase unit since the single-phase lateral that the PV system will be interconnected to will be converted to a three phase line. The total cost estimate to replace this single-phase recloser with the three phase Nova recloser is approximately $31,300. The revision to add a lockout relay to the Alamogordo South feeder breakers protection scheme is an additional cost of approximately $5,000.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Alamogordo Airport output exceeds the minimum load on Alamogordo South Feeder 12-83 during daylight hours. No Alamogordo South Feeder 12-83 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project kW and kWH output instantaneously and historically.

The following cost estimates for communication have been developed:

ONE-TIME Equipment COST	$ 35,000
One-Time Labor Cost	$ 10,000
MONTHLY Recurring O&M	$ 3,500

The breakdown of the ONE-TIME Equipment cost:

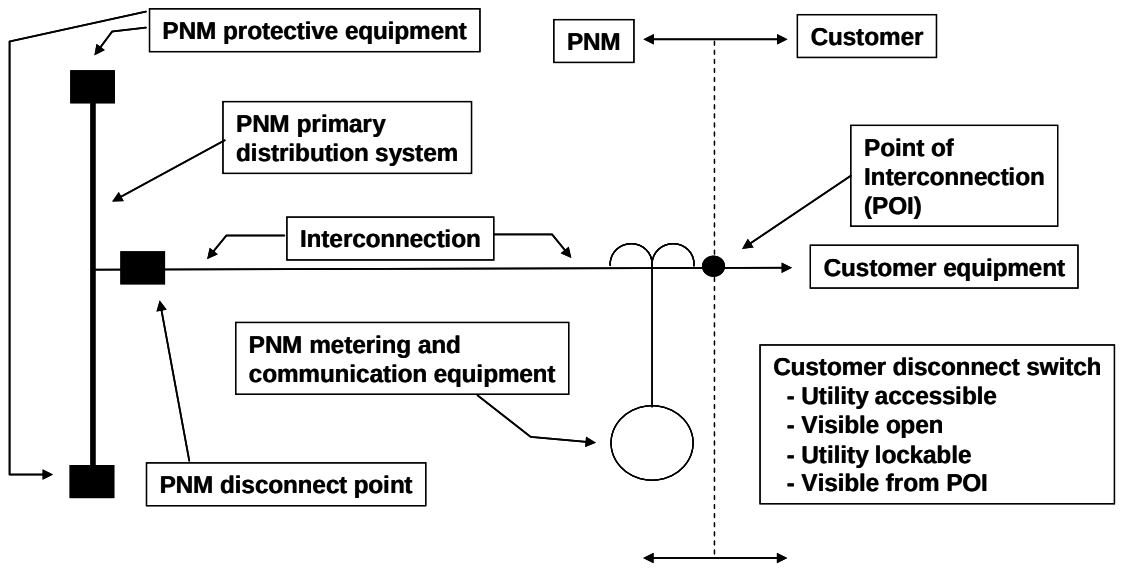
Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$ 20,000
Channel Bank Equipment	$ 10,000

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

The Project Alamogordo Airport to Alamogordo South Feeder 12-83 connection consists of:

- Approximately 1.4 miles of reconductor from single-phase, approximately 0.78 miles of 4 ACSR and 0.62 miles of 2 ACSR, to a three-phase line with 397 AAC conductor; as shown in Figure 4.
- Approximately .25 miles of new three-phase line with 397 AAC conductor, as shown in Figure 5.
- Install one S&C IntelliRupter switch (See Figure 5).
- Install riser to primary meter, about 20 ft, using 750 AL.

Figure 4 ***– Reconductor Sections***

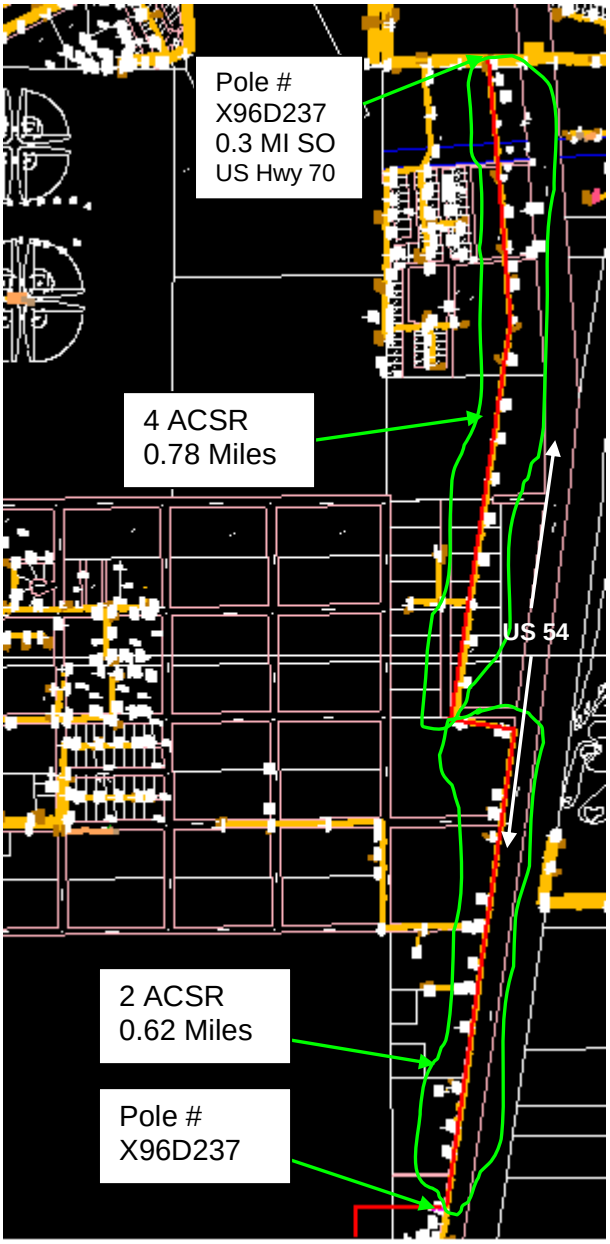
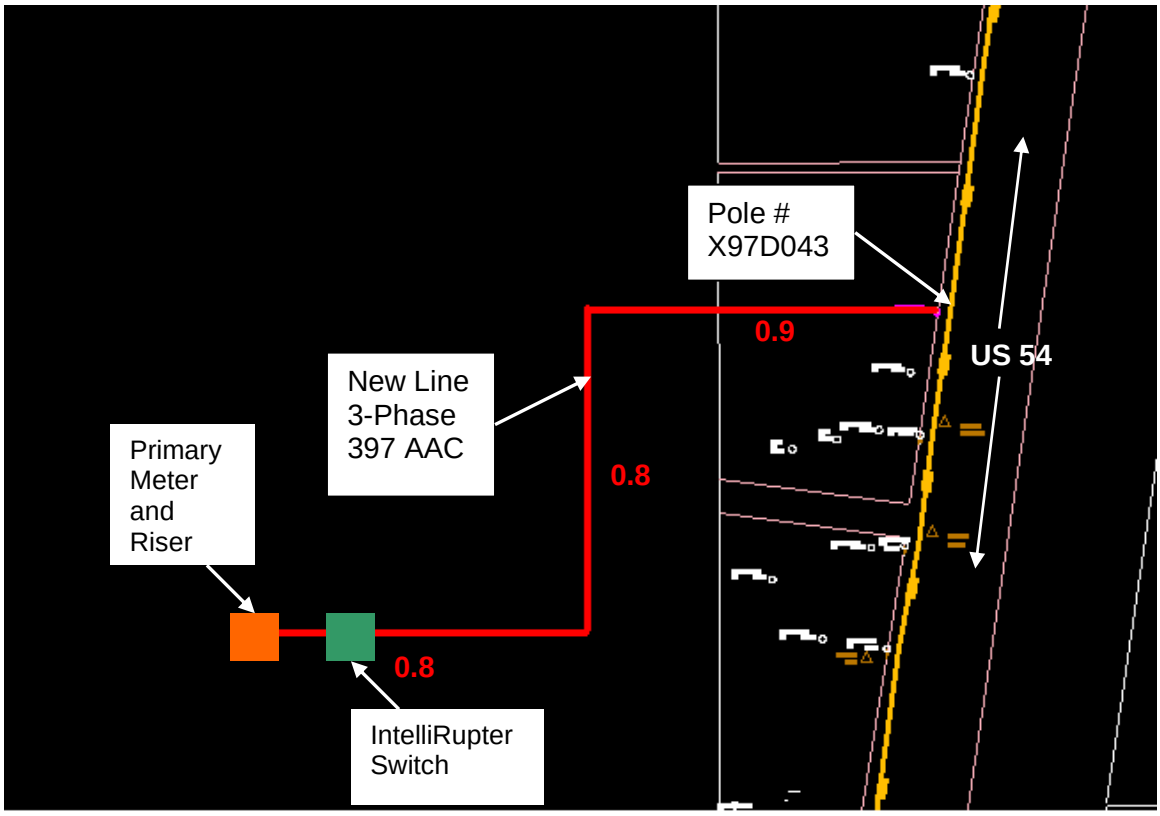


Figure 5 ***– New Line Sections***



13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 11.

Table 11 ***- Project Alamogordo Airport Interconnection Cost***

	ESTIMATED COSTS 2010$	ESTIMATED CONSTRUCTION TIME
PNM disconnect point (IntelliRupter)	$ 52,800	~16 week lead time ~3 days construction
Interconnection (Line Construction)	$ 176,000	~16 week lead time ~8.5 weeks construction
System Upgrades	$ 283,019	~16 week lead time ~8.5 weeks construction
PNM Primary Metering	$ 19,400	~3 week lead time ~4 days construction
Protection	$ 5,000	~16 week lead time ~3 days construction
Communications	$ 45,000	~16 week lead time ~3 weeks construction
TOTAL	**$ 581,219**	

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the Operating Procedures. The Operating Procedures may also require the facility to operate at 99% power factor importing reactive power as a condition to maintain interconnection to the EPS.

16.0 CONCLUSIONS

Project Alamogordo Airport does have an adverse impact on the PNM distribution system when operating at 100% power factor. Voltage control must be maintained by operating at a fixed power factor of 99% lagging. The Project location will result in an interconnection with Alamogordo South Feeder 12-83. When operating at a lagging 99% power factor, analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Switching capacitor banks on the feeder do not adversely impact voltages. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will cause a slight flow of electricity from the distribution system through the substation transformer, the difference is less than 5 MW, and therefore no transmission voltage issues are anticipated. The necessary upgrades to three-phase lines to accommodate the Project will eliminate any conductor thermal issues. Finally, analysis shows that Project Alamogordo Airport output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Alamogordo Airport and has determined that there are no adverse impacts associated with a 6,000 KW AC source connected to Alamogordo South Feeder 12-83 when operated at a fixed lagging 99% PF.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Alamogordo South Feeder 12-83 is maintained within established PNM voltage, equipment and fault protection criteria.

Project Alamogordo Airport
6 MW PV Generation Project

Small Generator Interconnection System Impact Study

(SGI-PNM-2010-09)

March 2011

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution Planning and Contracts

Electric
Transmission

Foreword

This report was prepared for Renewable Generation Development Department by Public Service Company of New Mexico Transmission Operations.

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Addendum (A) - List of Figures, Tables and Graphs

EXECUTIVE SUMMARY

Public Service Company of New Mexico Generation Planning and Development Department submitted a 'Small Generator Interconnection Request' for the installation of an inverter based grid-connected photovoltaic system nominally rated at 6,000 kW AC to the Public Service of New Mexico (PNM) distribution primary system. The primary location proposed for the installation is in Alamogordo, New Mexico at 2274 U.S. 54, approximately one mile south of U.S. 70. The request is identified as Project Alamogordo Airport and would be connected to Alamogordo South Feeder 12-83. An application was submitted based on the PNM large PV program.

The estimated cost of connecting Project Alamogordo Airport to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRupter)	$ 52,800	~16 week lead time ~3 days construction
Interconnection (Line Construction)	$ 176,000	~16 week lead time ~8.5 weeks construction
System Upgrades	$ 283,019	~16 week lead time ~8.5 weeks construction
PNM Primary Metering	$ 19,400	~3 week lead time ~4 days construction
Protection	$ 5,000	~16 week lead time ~3 days construction
Communications	$ 45,000	~16 week lead time ~3 weeks construction
TOTAL	**$ 581,219**	

On January 20, 2011 authorization was given to study an alternative point of interconnect for Project Alamogordo Airport 6MW PV, reference Section 17- Addendum A. The alternative location proposed for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 6,000 kW AC to the Public Service of New Mexico (PNM) distribution primary system is in Alamogordo, New Mexico at 1446 U.S. 70. For the purpose of clarity, this addendum will refer to Project Alamogordo Airport as Project Alamogordo Airport (Site 2).

The request for Project Alamogordo Airport (Site 2) would be connected to Alamogordo South Feeder 12-83.

The estimated cost of connecting Project Alamogordo Airport (Site 2) to the distribution primary is:

	ESTIMATED COSTS 2011$	ESTIMATED CONSTRUCTION TIME
PNM disconnect point (IntelliRupter)	$ 41,853	~16 week lead time ~1 days construction
Interconnection (Line Construction)	$14,534	~2 week lead time ~2 days construction
System Upgrades	$215,509	~2 week lead time ~9.5 weeks construction
PNM Primary Metering	$ 64,606	~3 week lead time ~5 days construction
Communications	$ 45,000	~16 week lead time ~3 weeks construction
TOTAL	**$381,502**	

Project Alamogordo Airport (Site 2) does have an adverse impact on the PNM distribution system when operating at 100% power factor (PF) output. Section 17 results show how utilizing a PF output of 99% lagging reduces high system voltage caused by the PV system. Project Alamogordo Airport (Site 2) would still be producing 5940 kW. Approximately 846 kVAr would need to be imported by the PV system.

The application notes the use of twelve SMA Sunny Central 500HE 509 kW inverters, which are presently not certified UL 1741 compliant inverters. The SMA Sunny Central 500HE inverter will have a 1000V DC rating and is designed to meet UL 1741 compliance standards. Since UL testing has not been completed on the 1000Vdc systems the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer technical data notes the inverter is capable of maintaining a unity power factor but also has the capability to control the reactive power to support voltage control. Due to voltage control issues identified in this report, voltage regulation will be required, which precludes the use of a UL 1741 compliant inverter. Distribution Planning recommends the use of a UL listed 1741 compliant inverter to insure, among other concerns, that the unit will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other various requirements as

called out in the SGIP application, Attachment 3. A complete field checkout of non-complaint equipment at the proposed facility is recommended before the facility can be considered certified for interconnection operation.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Alamogordo Airport and Project Alamogordo Airport (Site 2), have an adverse impact on the PNM distribution system when operating at 100% power factor (PF) output. The following results show how utilizing a PF output of 99% lagging eliminates the adverse impacts of the PV system. Project Alamogordo Airport would still be producing 5940 kW. Approximately 846 kVAr would need to be imported by the PV system.

The proposed Project locations will result in an interconnection with Alamogordo South Feeder 12-83 and analysis results with the inverter operating at 99% PF lagging were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud cover will not cause voltage flicker irritation problems.
4. Project output does cause conductors ratings to be exceeded; necessary reconductor is included in the interconnection cost.
5. The Project contribution to fault current does not adversely impact the protection coordination on Alamogordo South Feeder 12-83.
6. Project output will cause a flow of electricity from the distribution system through the substation transformer, but is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Alamogordo Airport and Project Alamogordo Airport (Site 2) and has determined that there are no adverse impacts associated with a 6,000 kVA AC source connected to Alamogordo

South Feeder 12-83 when operated at a fixed, lagging 99% power factor (5,940 kW + 846 kVAr).

Distribution Planning has also identified that system improvements are required to ensure that electric service to all customers on Alamogordo South Feeder 12-83 are maintained within established PNM voltage, equipment and fault protection criteria.

1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Alamogordo Airport or as Project Alamogordo Airport (Site 2). The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Alamogordo Airport proposes to connect a 6,000 KW AC PV facility to Alamogordo South Substation Feeder 12-83 in Alamogordo, NM. The Project will be located on the west side of US Highway 54 approximately 1.4 miles south of US Highway 70, just east of the Alamogordo Airport, as shown in Figure 1. The circuit distance from Alamogordo South Substation to the Project Alamogordo Airport point of interconnection (POI) is about 27,525 ft. or 5.21 miles.

Figure 1 ***– Project Alamogordo Airport Location***

3.0 SYSTEM CONFIGURATION

Project Alamogordo Airport is connected to Alamogordo South Feeder 12-83 served from Alamogordo South Substation. Table 1 shows the rating of Alamogordo South Substation as determined by manufacturer nameplate data.

Table 1 ***- Substation transformer nameplate rating***

Substation	Nameplate MVA Rating	Voltage Rating
Alamogordo SO	46.7	115-12.47

Table 2 shows the 2010 non-coincident peak summer loads for Alamogordo South Substation and feeders.

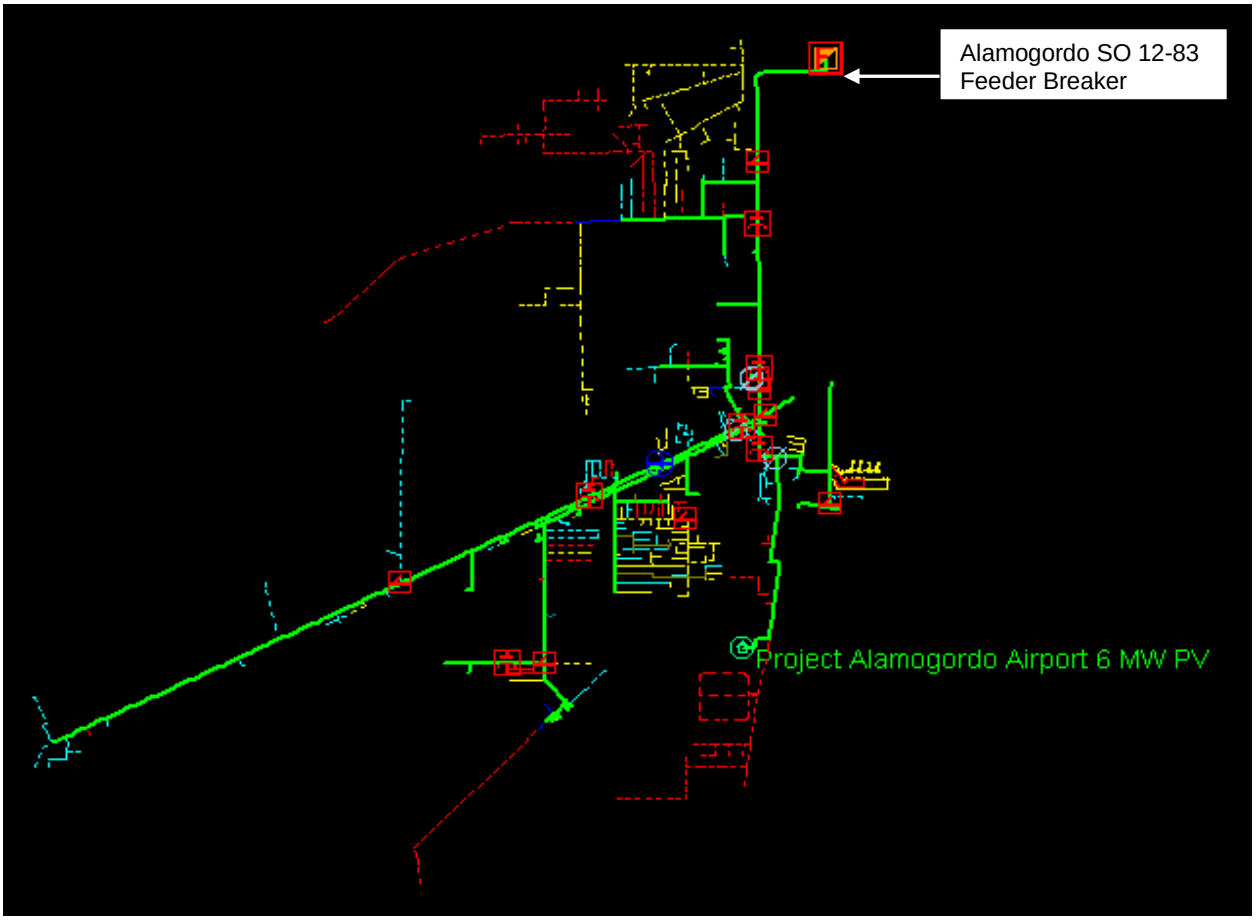
Table 2 ***- July 2010 Non-coincident Peak Loads***

Feeder	July 2010 Non-coincident Peak Load			
	KW	KVAr	KVA	% Power Factor
Alamogordo SO				
Fdr 12-83	7,582*	-446*	7,595*	-99.8*
Fdr 12-89	13,621*	2,897*	13,926*	97.8*
Alamo. SO Sub	21,245	1,162	21,276	99.9

* - Only individual feeder Amps available, kW/kVAr/kVA/pf estimated using historical data and capacitor bank consideration.

Figure 2 is a picture of the distribution feeder used in the Advantica SynerGEE modeling program.

Figure 2 – SynerGEE model of Alamogordo South Feeder 12-83



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading for the period August 1, 2009 through July 31, 2010 on the Alamogordo South Feeder 12-83 are shown in Table 3:

***Table 3* - Alamogordo South Feeder 12-83 max/min Daylight Hours Load**

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
June 5, 2010	5 PM	7,596	-478	7,611	-99.8%	320	328	375
Oct 4, 2009	7 AM	2,031	368	2,064	98.4%	88	91	96

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Alamogordo Airport at maximum output exceeds the load on Alamogordo South Feeder 12-83 at minimum daylight load timeframes. Therefore, Project Alamogordo Airport will cause a flow of power into Alamogordo South Substation. Table 4 shows the maximum and minimum daylight hours loading on the Alamogordo South Substation transformer for the period August 1, 2009 through July 31, 2010.

Table 4 ***- Alamogordo South Substation max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 14, 2010	5:00 PM	21,026	999	21,050	99.9	1,031	985	1,006
April 18, 2010	7:00 AM	5,827	-1,419	5,997	-97.2	245	248	259

The minimum daylight load on the Alamogordo South Substation transformer, as shown in Table 4, is slightly less than the rated output of Project Alamogordo Airport. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system.

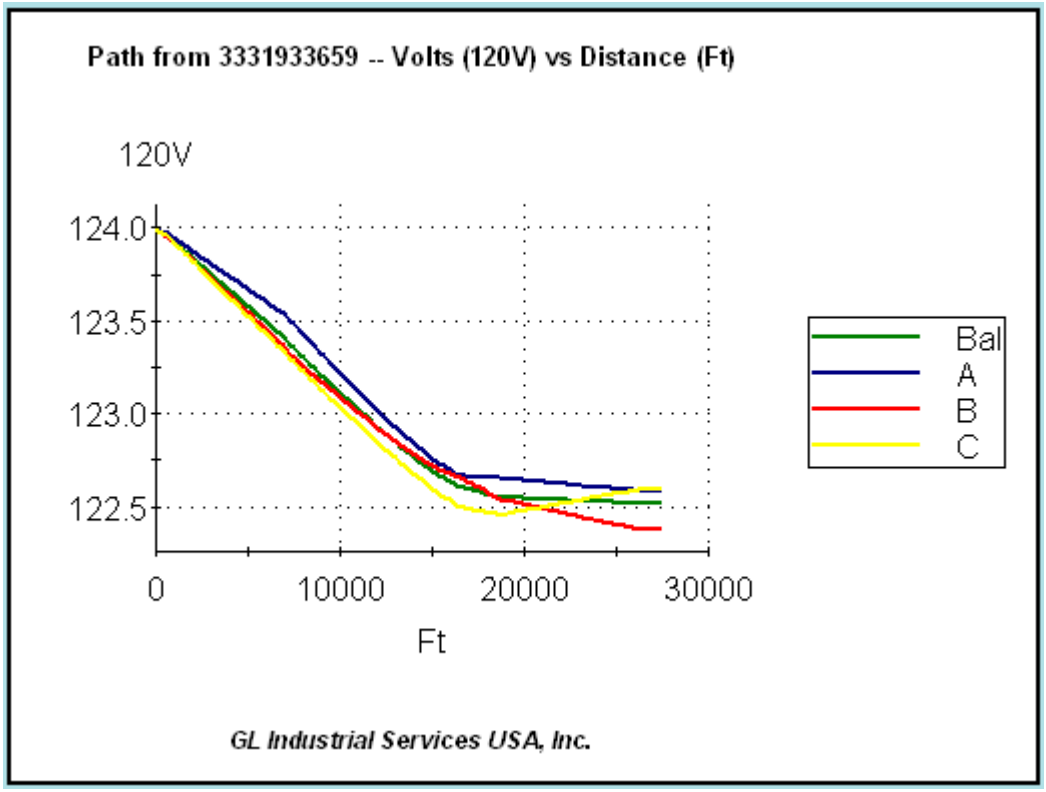
4.1 Voltage impacts on the transmission system

Although the minimum daylight load on the Alamogordo South Substation transformer is less than the rated output of the project, the difference is less than 5 MW; therefore no transmission related issues are anticipated to be associated with Project Alamogordo Airport.

4.2 Voltage impacts for minimum daylight hours load

The Alamogordo South Feeder 12-83 voltage for the feeder minimum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport, per the SynerGEE model, are shown in Graphs 1, 2, and 3.

Graph 1 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI without Project Alamogordo Airport for daylight hours minimum load on October 4, 2009

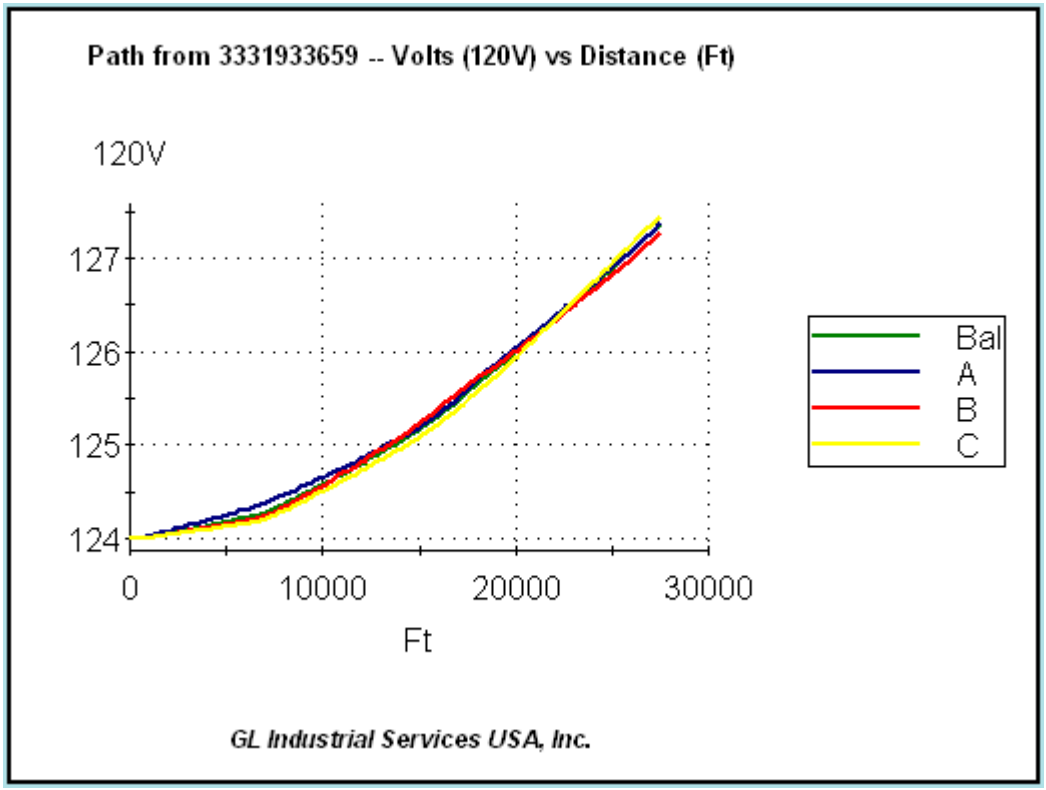


The model voltages at the point of interconnection are:

Phase A – 122.6 volts Phase B – 122.4 volts Phase C – 122.6 volts Balanced – 122.5 volts

The voltages on Alamogordo South Feeder 12-83 prior to the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on only fixed capacitor bank 1382279 (600 kVAr) being on.

Graph 2 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours minimum load on October 4, 2009, 100% PF output

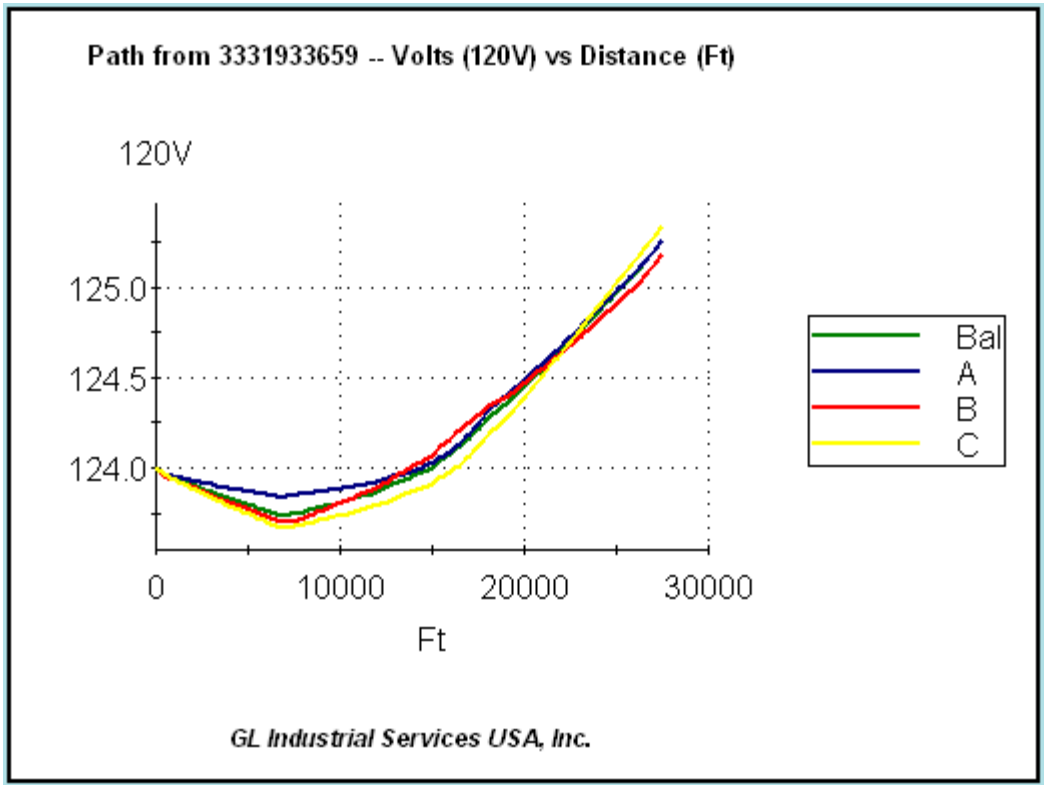


The model voltages at the point of interconnection are:

Phase A – 127.4 volts Phase B – 127.3 volts Phase C – 127.5 volts Balanced – 127.4 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 100% PF output, are outside the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. This model is based on only fixed capacitor bank 1382279 (600 kVAr) being on.

Graph 3 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours minimum load on October 4, 2009, 99% lagging PF output



The model voltages at the point of interconnection are:

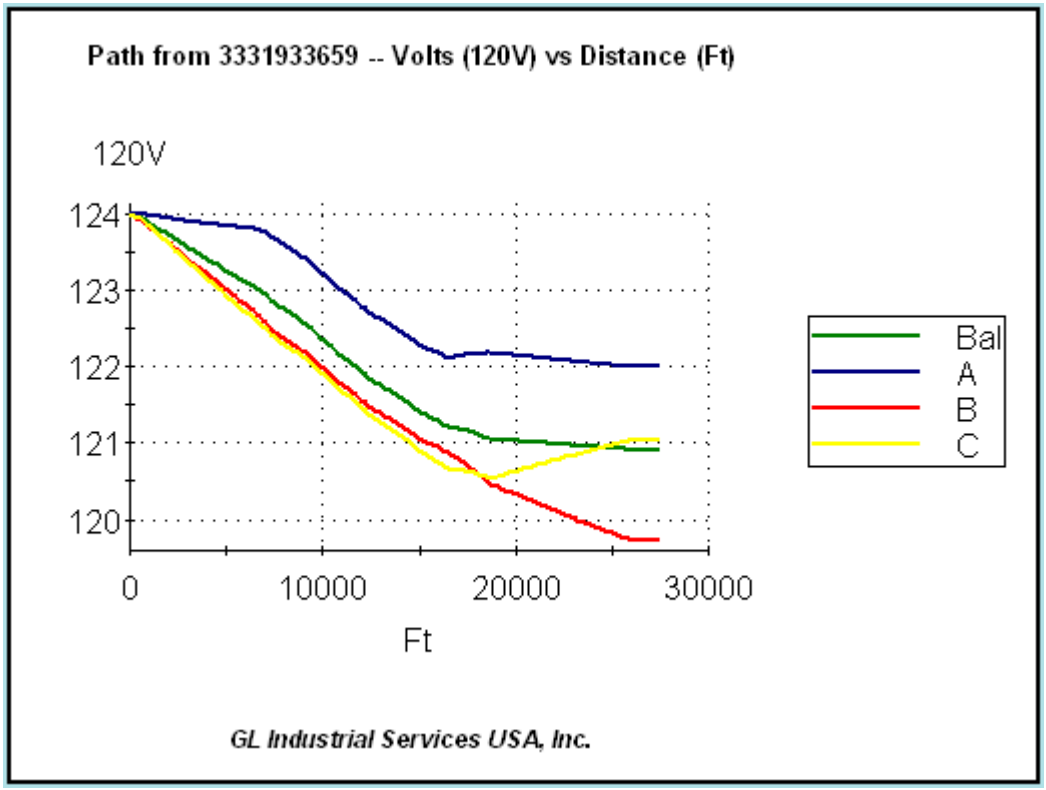
Phase A – 125.3 volts Phase B – 125.2 volts Phase C – 125.3 volts Balanced – 125.3 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 99% lagging PF output, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on only fixed capacitor bank 1382279 (600 kVAr) being on.

4.3 Voltage impacts for maximum daylight hours load

The Alamogordo South Feeder 12-83 voltage for the feeder maximum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport, per the SynerGEE model, are shown in Graphs 4, 5, and 6.

Graph 4 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI without Project Alamogordo Airport for daylight hours maximum load on June 5, 2010

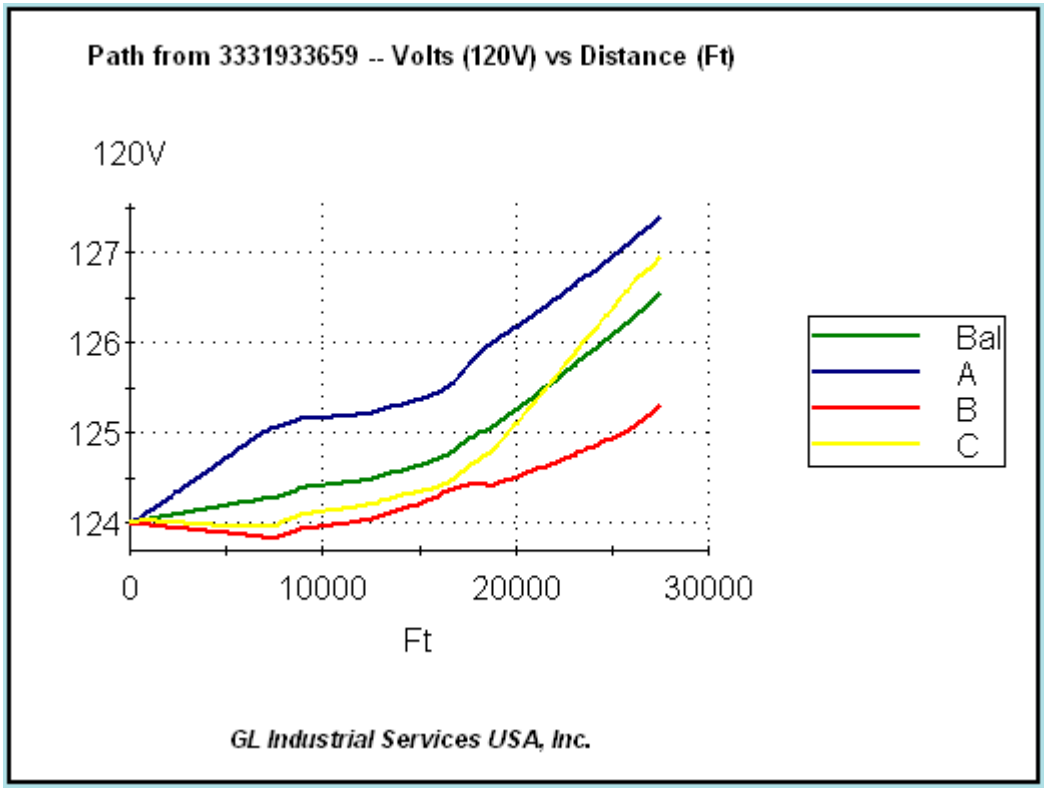


The model voltages at the point of interconnection are:

Phase A – 122.0 volts Phase B – 119.7 volts Phase C – 121.0 volts Balanced – 120.9 volts

The voltages on Alamogordo South Feeder 12-83 prior to the installation of Project Alamogordo Airport are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on all capacitor banks on Alamogordo South Feeder 12-83 (4200 kVAr total) energized.

Graph 5 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours maximum load on June 5, 2010, 100% PF output

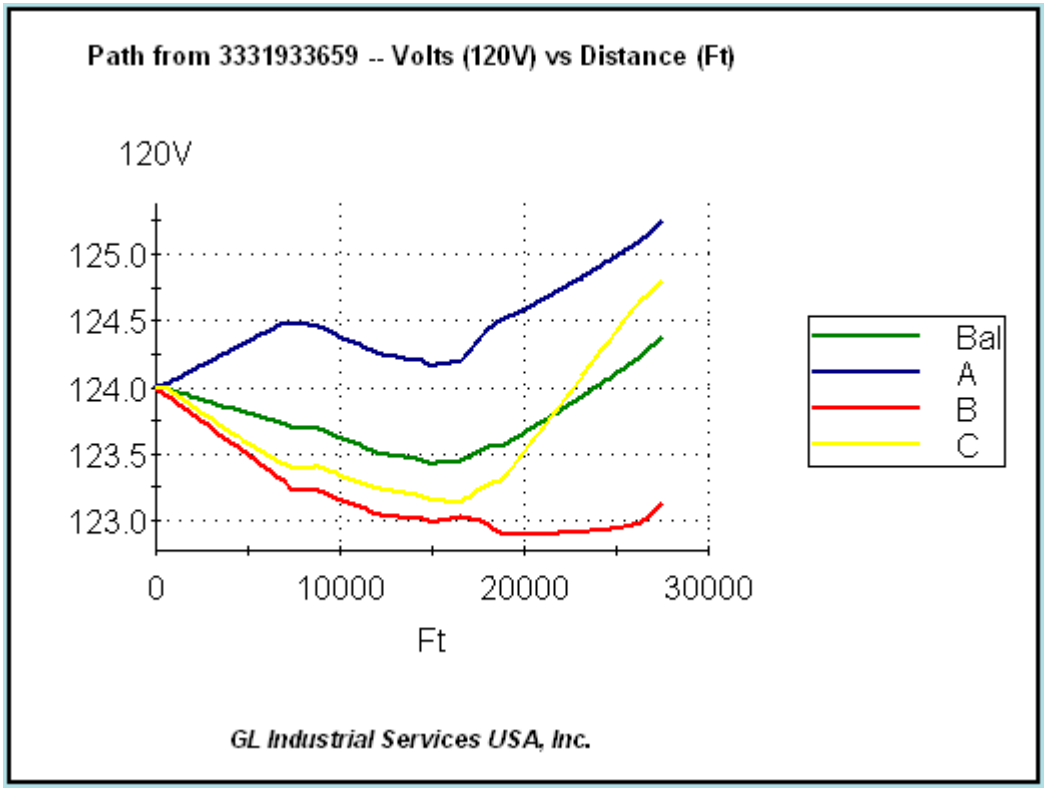


The model voltages at the point of interconnection are:

Phase A –127.4 volts Phase B – 125.3 volts Phase C – 127.0 volts Balanced – 126.6 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 100% PF output, are outside the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. This model is based on all capacitor banks on Alamogordo South Feeder 12-83 (4200 kVAr total) energized.

Graph 6 - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport for daylight hours maximum load on June 5, 2010, 99% lagging PF output



The model voltages at the point of interconnection are:

Phase A –125.2 volts Phase B – 123.1 volts Phase C – 124.8 volts Balanced – 124.4 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport, at 99% lagging PF output, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on all capacitor banks on Alamogordo South Feeder 12-83 (4200 kVAr total) energized.

In conclusion, Project Alamogordo Airport output does cause the voltage on Alamogordo South Feeder 12-83 to increase to unacceptable levels when allowed to operate at 100% PF. Operating at 99% lagging PF allows the voltage to stay within the PNM criteria of ANSI C84.1 and is acceptable.

Review under contingency transfer was not conducted since feeder Alamogordo South 12-83, under any pertinent contingencies, is simply transferred using the substation bus tie breaker and therefore not necessary.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Alamogordo South Feeder 12-83 has a voltage regulator installed on the feeder, but it is downstream from Project Alamogordo Airport. The substation LTC is set at 124 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 122.5 volts and will reduce the voltage if the substation bus is above 125.5 volts.

As seen in Tables 5-8, the SynerGEE modeling shows the LTC did not change position for a 6,000 kW source on the feeder for high or low load periods. This is not considered an adverse impact.

Project Alamogordo Airport was modeled as a source on Alamogordo South Substation connected to the end of Alamogordo South Feeder 12-83. The SynerGEE model included the substation transformer and Alamogordo South Feeders 12-83 and 12-89. The substation bus voltage and load tap changer position for maximum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport 6 MW, at a 99% lagging PF operation, per the SynerGEE model, are shown in Tables 5 and 6.

***Table 5* – Alamogordo South Substation with Project Alamogordo Airport OFF for daylight hours maximum load on July 14, 2010**

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.2	124.1	124.1
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 5. The voltages at Alamogordo South Substation prior to the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 6 ***– Alamogordo South Substation with Project Alamogordo Airport ON at 99% lagging PF for daylight hours maximum load on July 14, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.2	124.3	124.3	124.3
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 6. The voltages at Alamogordo South Substation after the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The substation bus voltage and load tap changer position for minimum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport 6 MW, at a 99% lagging PF operation, per the SynerGEE model, are shown in Tables 7 and 8.

Table 7 ***– Alamogordo South Substation with Project Alamogordo Airport OFF for daylight hours minimum load on April 18, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.1	124.1	124.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 7. The voltages at Alamogordo South Substation prior to the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8 ***– Alamogordo South Substation with Project Alamogordo Airport ON at 99% lagging PF for daylight hours minimum load on April 18, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.1	124.1	124.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 8. The voltages at Alamogordo South Substation after the installation of Project Alamogordo Airport are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Alamogordo South Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of Project Alamogordo Airport output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a

distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Alamogordo Airport POI is shown in Section 4.0. Table 9 summarizes the voltage and the calculated voltage flicker for the worst case phase. Table 10 is based on the GE flicker graph.

Table 9 ***- Voltage flicker on Alamogordo South Feeder 12-83 due to Project Alamogordo Airport at -99% PF Output***

	POI Voltage Alamogordo South Feeder 12-83 Loading	
	Minimum (B-Phase)	**Maximum (C-Phase)**
Without Project	122.4	121.0
With Project	125.2	124.8
% Voltage Flicker	**2.29**	**3.14**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 10 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
2.29 (Min)	1.5/hour	26/hour
3.14 (Max)	Always Visible	10/hour

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 9 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 10. Distribution voltage flicker resulting from changes in Project Alamogordo Airport output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Alamogordo Airport POI to the substation were reviewed using the SynerGEE feeder model with and without Project Alamogordo Airport's maximum output of 6,000 kW AC.

There were no conductor loading problems from the POI to the substation on Alamogordo South Feeder 12-83 with Project Alamogordo Airport OFF. However, with Project Alamogordo Airport at maximum output, there were conductor loading problems. The estimate includes necessary line upgrade to 397 AAC conductor.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system in Alamogordo are controlled by a time setting, temperature setting, or voltage setting. These settings vary from bank to bank in this area.

An inverter based grid connection will be a real power source (Watts only, no VArs) for the distribution system when operated at 100% PF. For this study, Project Alamogordo Airport was found to cause adverse impacts on the system for a 100% PF operation, so operation of 99% lagging PF is necessary. Regardless, when the inverter is operating and injecting watts, the power factor of the distribution feeder will appear to become worse.

Alamogordo South Feeder 12-83 has 4,200 total kVAr in capacitor banks (5x600 kVAr and 1x1200 kVAr). The June 2010 peak load on the feeder was estimated at 7,596 kW – j 478 kVAr or 7,611 kVA at a 99.8% leading power factor (i.e. 100.2% power factor). All capacitors were energized. Project Alamogordo Airport at a 5,940 kW + 846 kVAr AC output would change the apparent feeder loading to 1,656 kW + j 368 kVAr or 1,696 kVA at a 97.6% lagging power factor.

Project Alamogordo Airport may cause a PF as low as 97.6% lagging on Alamogordo South Feeder 12-83, but no voltage issues were identified and the resulting new power factor would be acceptable.

9.0 PROTECTION

Alamogordo South Substation feeder 12-83 is protected by a 1200 Amp free standing breaker with three Westinghouse, CO-9 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO phase relays and one Westinghouse, CO residual ground relay. The transformer protection is three Westinghouse, HU-1 differential relays. The Alamogordo Airport Project PV system will be connected to the system approximately 5.21 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 Amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to a new three-phase Nova recloser. The available fault current at the recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate

protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder; however the available fault current from the PV system is higher than the ground pickup on the feeder relay. The unit sub protection scheme will need to be modified to trip and lockout the feeder breakers 12-67, 12-83, 12-89 and 12-7 for a bus fault where the backup ground relay protecting the bus operates.

Project Alamogordo Airport requires a system protection improvement to be made to the Alamogordo South Substation feeder 12-83. Recloser R12327A will be replaced, due to distribution protections' recommendation, with a three phase unit since the single-phase lateral that the PV system will be interconnected to will be converted to a three phase line. The total cost estimate to replace this single-phase recloser with the three phase Nova recloser is approximately $31,300. The revision to add a lockout relay to the Alamogordo South feeder breakers protection scheme is an additional cost of approximately $5,000.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Alamogordo Airport output exceeds the minimum load on Alamogordo South Feeder 12-83 during daylight hours. No Alamogordo South Feeder 12-83 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for

billing and system status. The status will be for purposes of determining Project kW and kWH output instantaneously and historically.

The following cost estimates for communication have been developed:

ONE-TIME Equipment COST	$ 35,000
One-Time Labor Cost	$ 10,000
MONTHLY Recurring O&M	$ 3,500

The breakdown of the ONE-TIME Equipment cost:

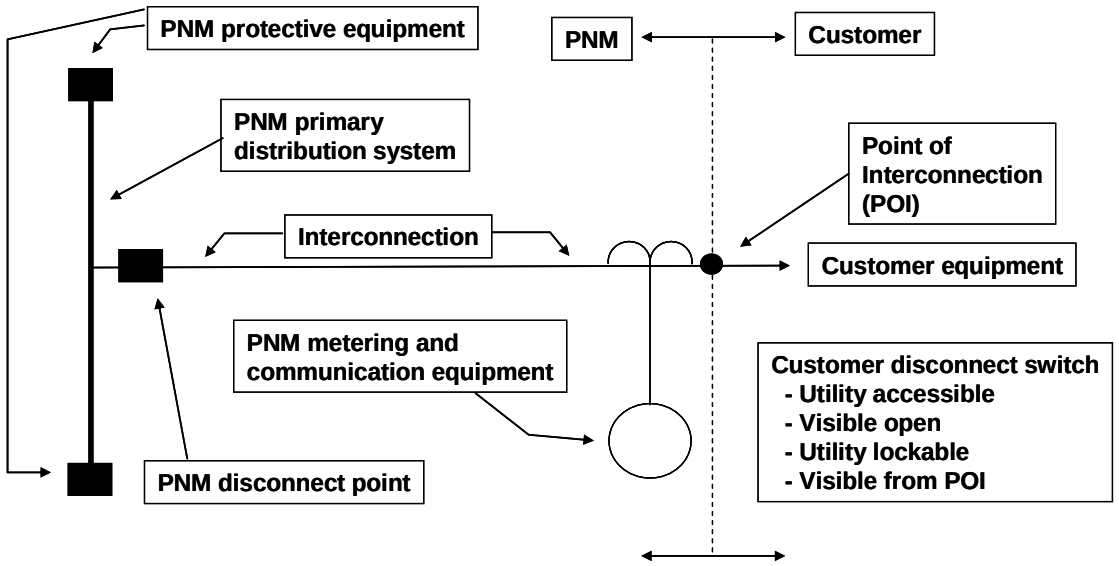
Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$ 20,000
Channel Bank Equipment	$ 10,000

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

The Project Alamogordo Airport to Alamogordo South Feeder 12-83 connection consists of:

- Approximately 1.4 miles of reconductor from single-phase, approximately 0.78 miles of 4 ACSR and 0.62 miles of 2 ACSR, to a three-phase line with 397 AAC conductor; as shown in Figure 4.
- Approximately .25 miles of new three-phase line with 397 AAC conductor, as shown in Figure 5.
- Install one S&C IntelliRupter switch (See Figure 5).
- Install riser to primary meter, about 20 ft, using 750 AL.

Figure 4 *– Reconductor Sections*

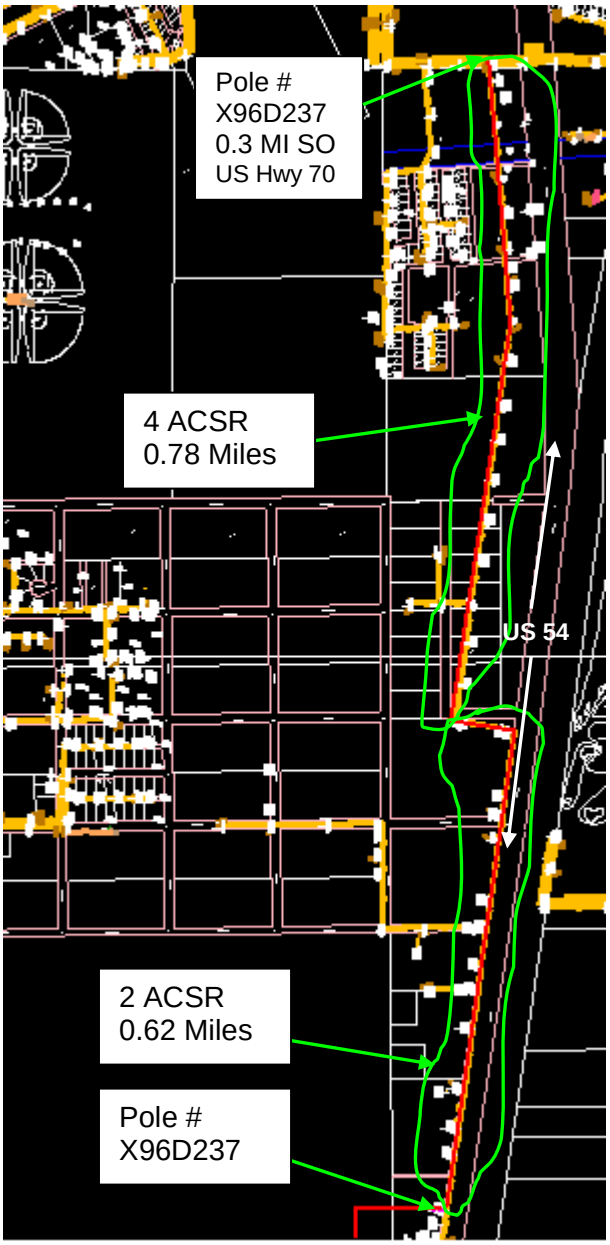
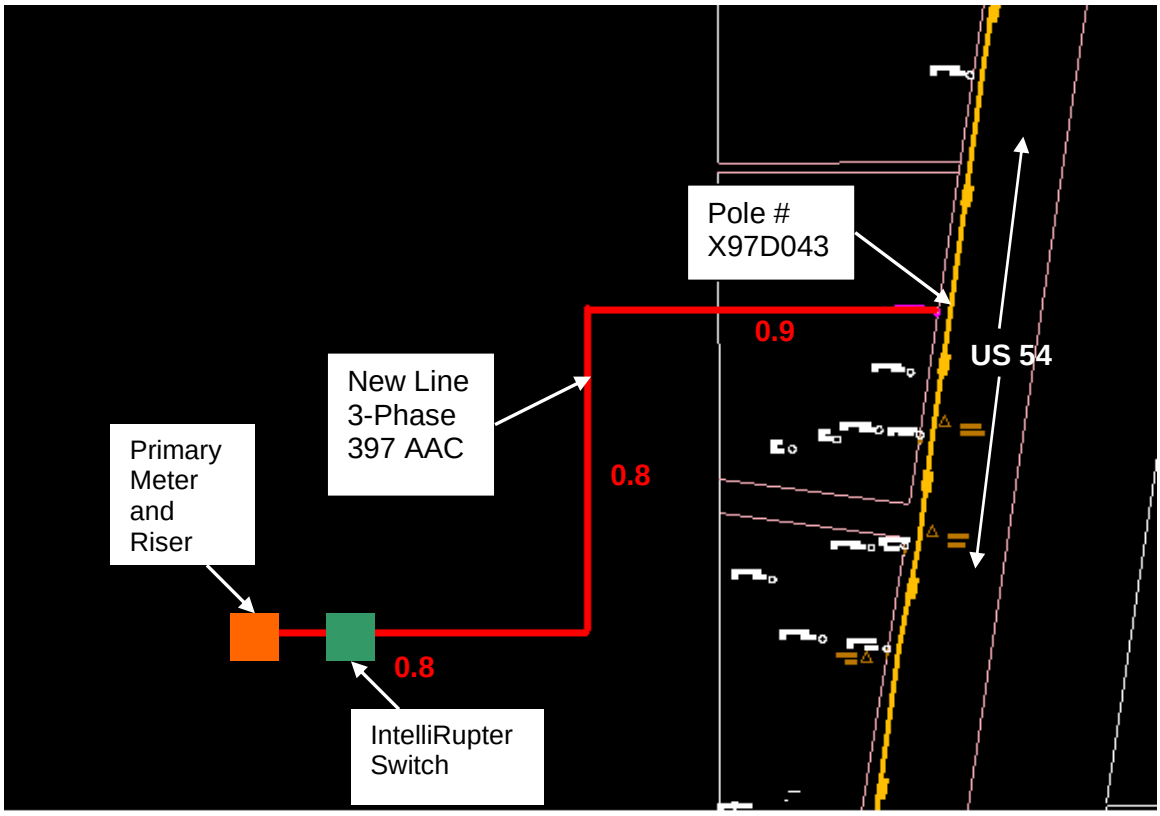


Figure 5 ***– New Line Sections***



13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 11.

Table 11 ***- Project Alamogordo Airport Interconnection Cost***

	ESTIMATED COSTS 2010$	ESTIMATED CONSTRUCTION TIME
PNM disconnect point (IntelliRupter)	$ 52,800	~16 week lead time ~3 days construction
Interconnection (Line Construction)	$ 176,000	~16 week lead time ~8.5 weeks construction
System Upgrades	$ 283,019	~16 week lead time ~8.5 weeks construction
PNM Primary Metering	$ 19,400	~3 week lead time ~4 days construction
Protection	$ 5,000	~16 week lead time ~3 days construction
Communications	$ 45,000	~16 week lead time ~3 weeks construction
TOTAL	**$ 581,219**	

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA). The NOA may also require the facility to operate at 99% power factor importing reactive power as a condition to maintain interconnection to the EPS.

16.0 CONCLUSIONS

Project Alamogordo Airport does have an adverse impact on the PNM distribution system when operating at 100% power factor. Voltage control must be maintained by operating at a fixed power factor of 99% lagging. The Project location will result in an interconnection with Alamogordo South Feeder 12-83. When operating at a lagging 99% power factor, analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Switching capacitor banks on the feeder do not adversely impact voltages. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will cause a slight flow of electricity from the distribution system through the substation transformer, the difference is less than 5 MW, and therefore no transmission voltage issues are anticipated. The necessary upgrades to three-phase lines to accommodate the Project will eliminate any conductor thermal issues. Finally, analysis shows that Project Alamogordo Airport output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Alamogordo Airport and has determined that there are no adverse impacts associated with a 6,000 KW AC source connected to Alamogordo South Feeder 12-83 when operated at a fixed lagging 99% PF.

Distribution Planning has determined that some system improvements are required to ensure that electric service to all customers on Alamogordo South Feeder 12-83 is maintained within established PNM voltage, equipment and fault protection criteria.

17.0 ADDENDUM (A)

On January 20, 2011 authorization was given to study an alternative point of interconnect for Project Alamogordo Airport 6MW PV. The following addendum will address relevant changes to subject matter contained within the original report issued in October 2010.

17.1 EXECUTIVE SUMMARY

The proposed alternative location for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 6,000 kW AC to the Public Service of New Mexico (PNM) distribution primary system is in Alamogordo, New Mexico at 1446 U.S. 70. The initial request is identified as Project Alamogordo Airport and would be connected to Alamogordo South Feeder 12-83. For the purpose of clarity, this addendum will refer to Project Alamogordo Airport as Project Alamogordo Airport (Site 2).

The estimated cost of connecting Project Alamogordo Airport (Site 2) to the distribution primary is:

	ESTIMATED COSTS 2011$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (IntelliRupter)	$ 41,853	~16 week lead time ~1 days construction
Interconnection (Line Construction)	$14,534	~2 week lead time ~2 days construction
System Upgrades	$215,509	~2 week lead time ~9.5 weeks construction
PNM Primary Metering	$ 64,606	~3 week lead time ~5 days construction
Communications	$ 45,000	~16 week lead time ~3 weeks construction
TOTAL	**$381,502**	

Project Alamogordo Airport (Site 2) does have an adverse impact on the PNM distribution system when operating at 100% power factor (PF) output. The following results show how utilizing a PF output of 99% lagging reduces high system voltage caused by the PV system. Project Alamogordo Airport (Site 2) would still be producing 5940 kW. Approximately 846 kVAr would need to be imported by the PV system.

The Project location will result in an interconnection with Alamogordo South Feeder 12-83 and analysis results with the inverter operating at 99% PF lagging were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud cover will not cause voltage flicker irritation problems.
4. Project output does cause conductors ratings to be exceeded; necessary reconductor is included in the interconnection cost.
5. The Project contribution to fault current does not adversely impact the protection coordination on Alamogordo South Feeder 12-83.
6. Project output will cause a flow of electricity from the distribution system through the substation transformer, but is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Alamogordo Airport (Site 2) and has determined that there are no adverse impacts associated with a 6,000 kVA AC source connected to Alamogordo South Feeder 12-83 when operated at a fixed, lagging 99% power factor (5,940 kW + 846 kVAr).

Distribution Planning has determined that some system improvements are required to ensure that electric service to all customers on Alamogordo South Feeder 12-83 is maintained within established PNM voltage, equipment and fault protection criteria.

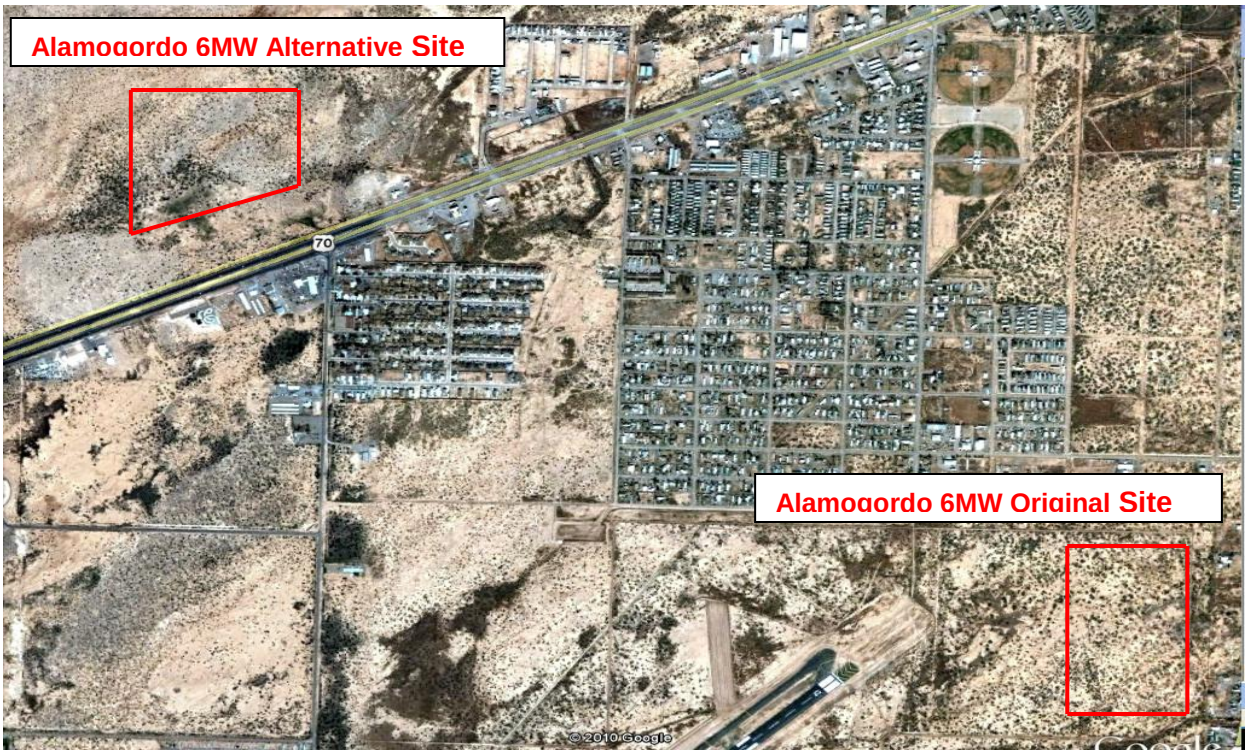
17.2 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Alamogordo Airport (Site 2). The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

17.2 PROJECT LOCATION

Project Alamogordo Airport (Site 2) proposes to connect a 6,000 KW AC PV facility to Alamogordo South Substation Feeder 12-83 in Alamogordo, NM. The previous location of Project Alamogordo Airport was located on the west side of US Highway 54 approximately 1.4 miles south of US Highway 70, just east of the Alamogordo Airport, as shown in Figure 1. The alternative site location is north of 1446 U.S. Highway 70 as seen in Figure 1A. The circuit distance from Alamogordo South Substation to the Project Alamogordo Airport point of interconnection (POI) is about 26,815 ft. or 5.08 miles.

Figure 1A ***– Alternate Project Alamogordo Airport Location***



17.3 SYSTEM CONFIGURATION

Project Alamogordo Airport (Site 2) is connected to Alamogordo South Feeder 12-83 served from Alamogordo South Substation. Table 1A shows the rating of Alamogordo South Substation as determined by manufacturer nameplate data.

Table 1A *- Substation transformer nameplate rating*

Substation	Nameplate MVA Rating	Voltage Rating
Alamogordo SO	46.7	115-12.47

Table 2A shows the 2010 non-coincident peak summer loads for Alamogordo South Substation and feeders.

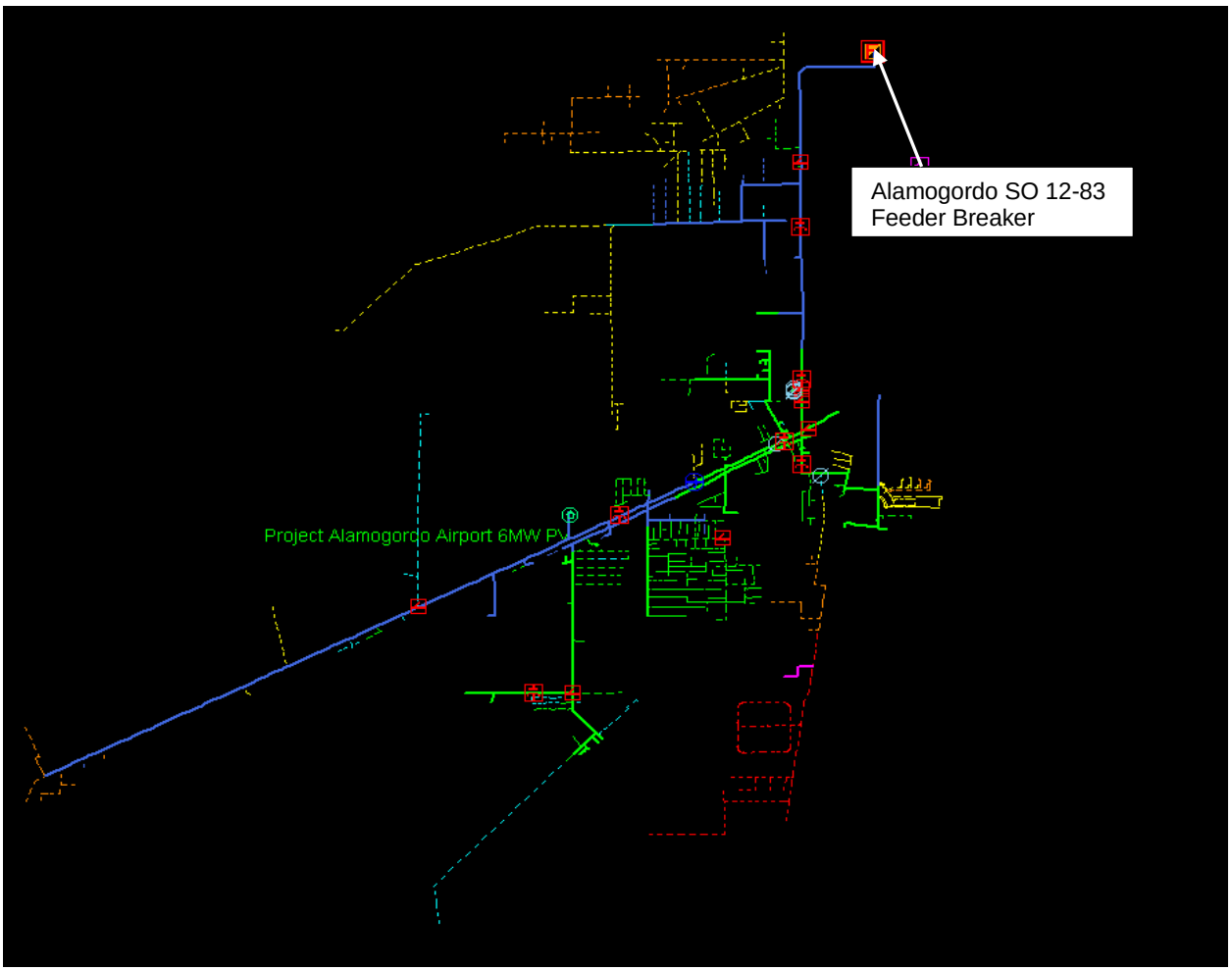
Table 2A *- July 2010 Non-coincident Peak Loads*

Feeder	July 2010 Non-coincident Peak Load			
	KW	KVAr	KVA	% Power Factor
Alamogordo SO				
Fdr 12-83	7,582*	-446*	7,595*	-99.8*
Fdr 12-89	13,621*	2,897*	13,926*	97.8*
Alamo. SO Sub	21,245	1,162	21,276	99.9

* - Only individual feeder Amps available, kW/kVAr/kVA/pf estimated using historical data and capacitor bank consideration.

Figure 2A is a picture of the distribution feeder used in the Advantica SynerGEE modeling program.

Figure 2A ***– SynerGEE model of Alamogordo South Feeder 12-83***



17.4 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading for the period August 1, 2009 through July 31, 2010 on the Alamogordo South Feeder 12-83 are shown in Table 3A:

Table 3A *- Alamogordo South Feeder 12-83 max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
June 5, 2010	5 PM	7,596	-478	7,611	-99.8%	320	328	375
Oct 4, 2009	7 AM	1436	-1457	2,046	-70.2%	88	91	96

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Alamogordo Airport (Site 2) at maximum output exceeds the load on Alamogordo South Feeder 12-83 at minimum daylight load timeframes. Therefore, Project Alamogordo Airport (Site 2) will cause a flow of power into Alamogordo South Substation. Table 4A shows the maximum and minimum daylight hours loading on the Alamogordo South Substation transformer for the period August 1, 2009 through July 31, 2010.

Table 4A *- Alamogordo South Substation max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 14, 2010	5:00 PM	21,026	999	21,050	99.9	1,031	985	1,006
April 18, 2010	7:00 AM	5,827	-1,419	5,997	-97.2	245	248	259

The minimum daylight load on the Alamogordo South Substation transformer, as shown in Table 4A, is slightly less than the rated output of Project Alamogordo Airport (Site 2). This will result in electricity flowing from the distribution system through the substation transformer to the transmission system.

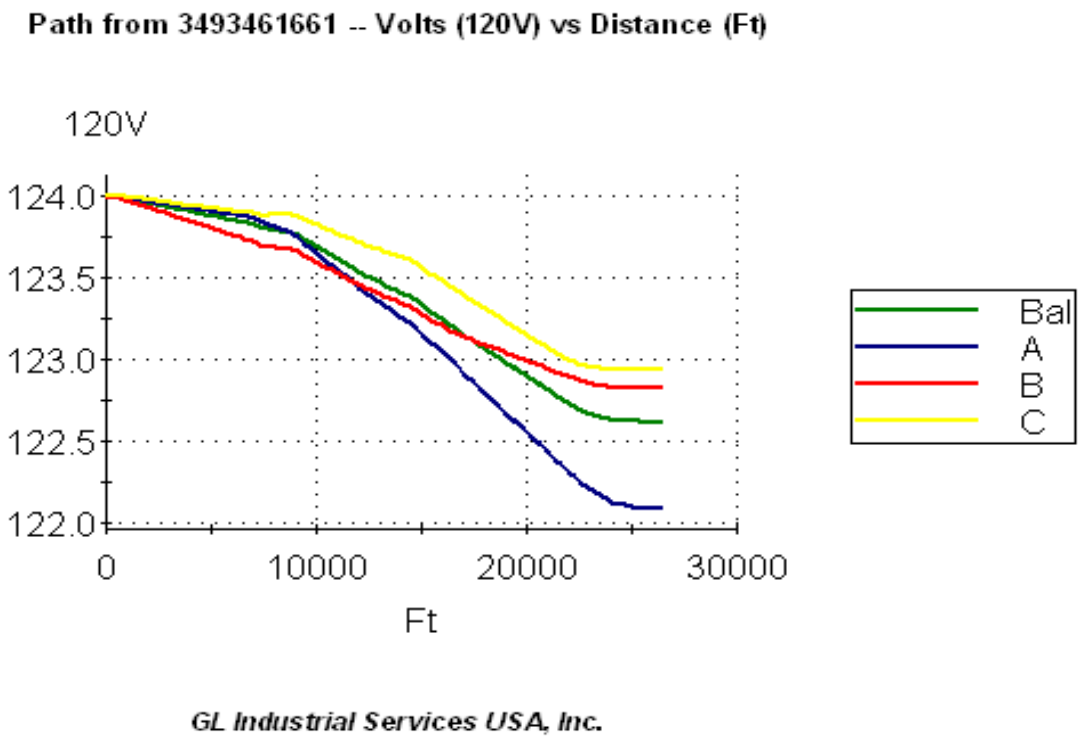
17.4.1 Voltage impacts on the transmission system

Although the minimum daylight load on the Alamogordo South Substation transformer is less than the rated output of the project, the difference is less than 5 MW; therefore no transmission related issues are anticipated to be associated with Project Alamogordo Airport (Site 2).

17.4.2 Voltage impacts for minimum daylight hours load

The Alamogordo South Feeder 12-83 voltage for the feeder minimum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport (Site 2), per the SynerGEE model, are shown in Graphs 1A, 2A, and 3A. Results show the impact Project Alamogordo Airport (Site 2) on Alamogordo South Feeder 12-83 without a three-phase voltage regulator and the replacement of 2-600kVAr capacitor banks with one temperature controlled switched 1200kVAr capacitor bank.

Graph 1A - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI without Project Alamogordo Airport (Site 2) for daylight hours minimum load on October 4, 2009

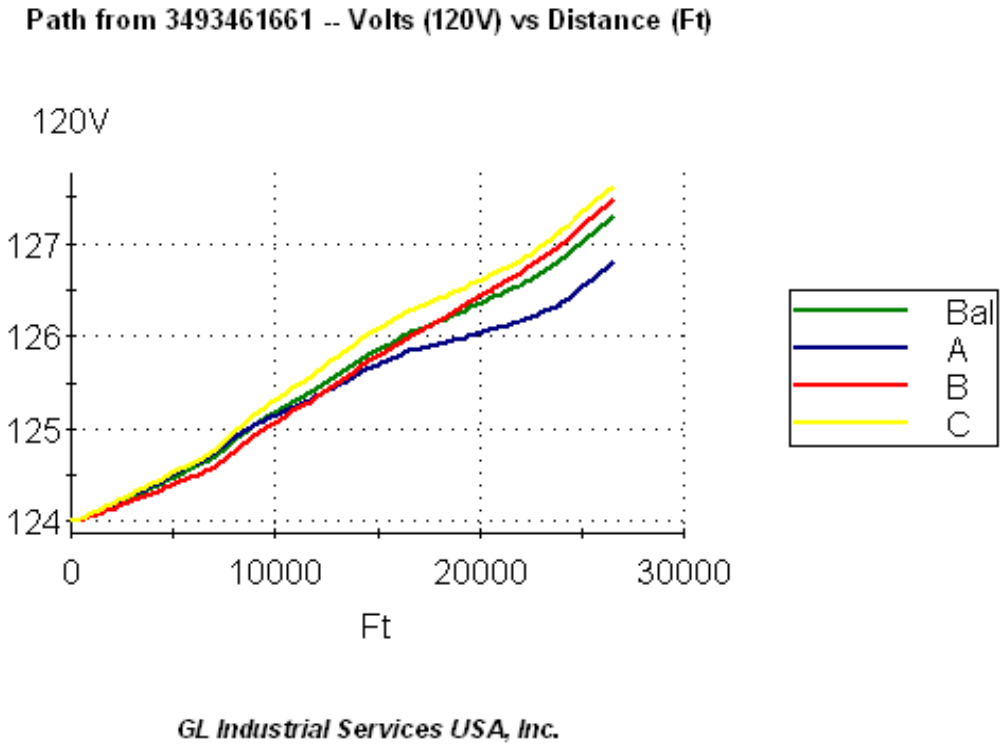


The model voltages at the point of interconnection are:

Phase A – 122.1 volts Phase B – 122.8 volts Phase C – 122.9 volts Balanced – 122.6 volts

The voltages on Alamogordo South Feeder 12-83 prior to the installation of Project Alamogordo Airport (Site 2) are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on all fixed capacitor banks (1800 kVAr total) being online.

Graph 2A - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport (Site 2) for daylight hours minimum load on October 4, 2009, 100% PF output

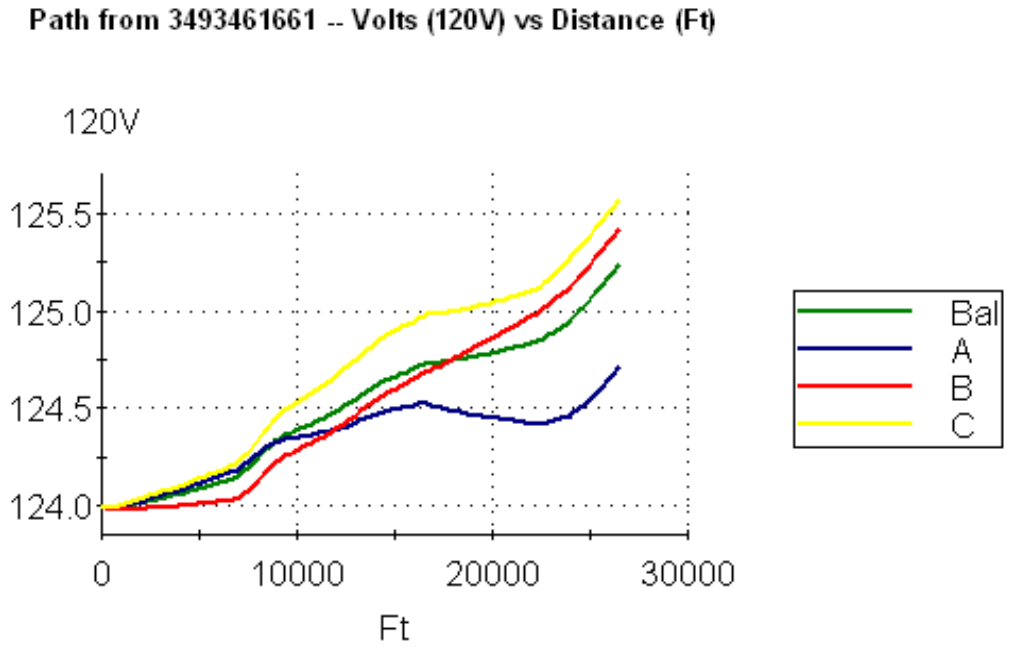


The model voltages at the point of interconnection are:

Phase A – 126.8 volts Phase B – 127.5 volts Phase C – 127.6 volts Balanced – 127.3 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport (Site 2), at 100% PF output, are outside the PNM voltage criteria (ANSI C84.1) at the POI and are not acceptable. This model is based on all fixed capacitor banks (1800 kVAr total) being online.

Graph 3A - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport (Site 2) for daylight hours minimum load on October 4, 2009, 99% lagging PF output



GL Industrial Services USA, Inc.

The model voltages at the point of interconnection are:

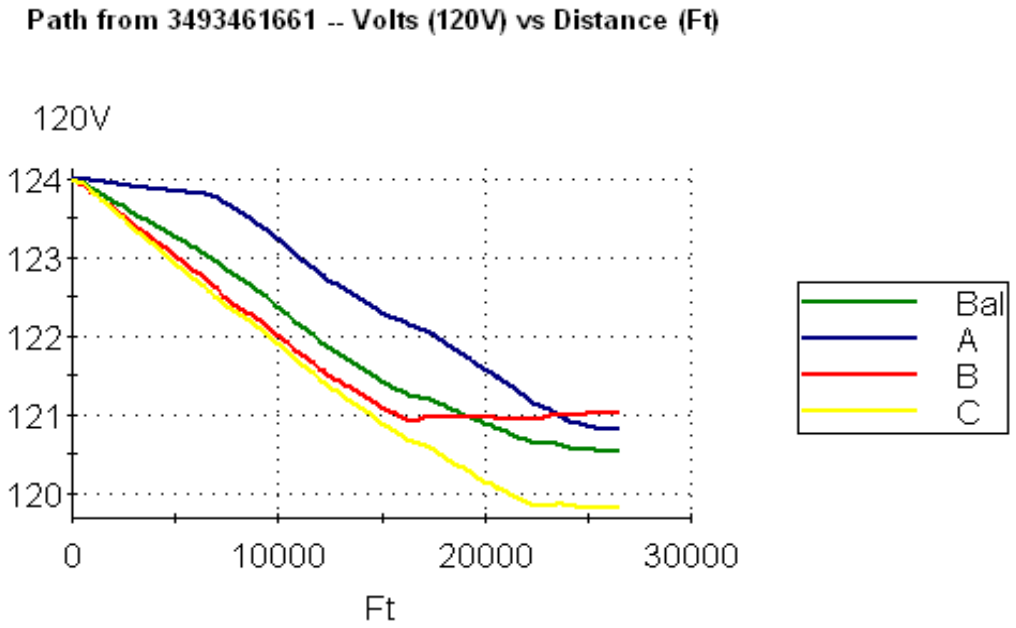
Phase A – 124.7 volts Phase B – 125.4 volts Phase C – 125.6 volts Balanced – 125.2 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport (Site 2), at 99% lagging PF output, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on all fixed capacitor banks (1800 kVAr total) being online.

17.4.3 Voltage impacts for maximum daylight hours load

The Alamogordo South Feeder 12-83 voltage for the feeder maximum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport (Site 2), per the SynerGEE model, are shown in Graphs 4A, 5A, and 6A. Results show the impact Project Alamogordo Airport (Site 2) on Alamogordo South Feeder 12-83 without a three-phase voltage regulator. Additionally, during the maximum system loading on Alamogordo 12-83, two switched 1200kVAr capacitor banks are energized, bringing the total capacitor banks on Alamogordo 12-83 to 3-600kVAr fixed banks and 2-1200kVAr switched banks (4200kVAr).

Graph 4A - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI without Project Alamogordo Airport (Site 2) for daylight hours maximum load on June 5, 2010



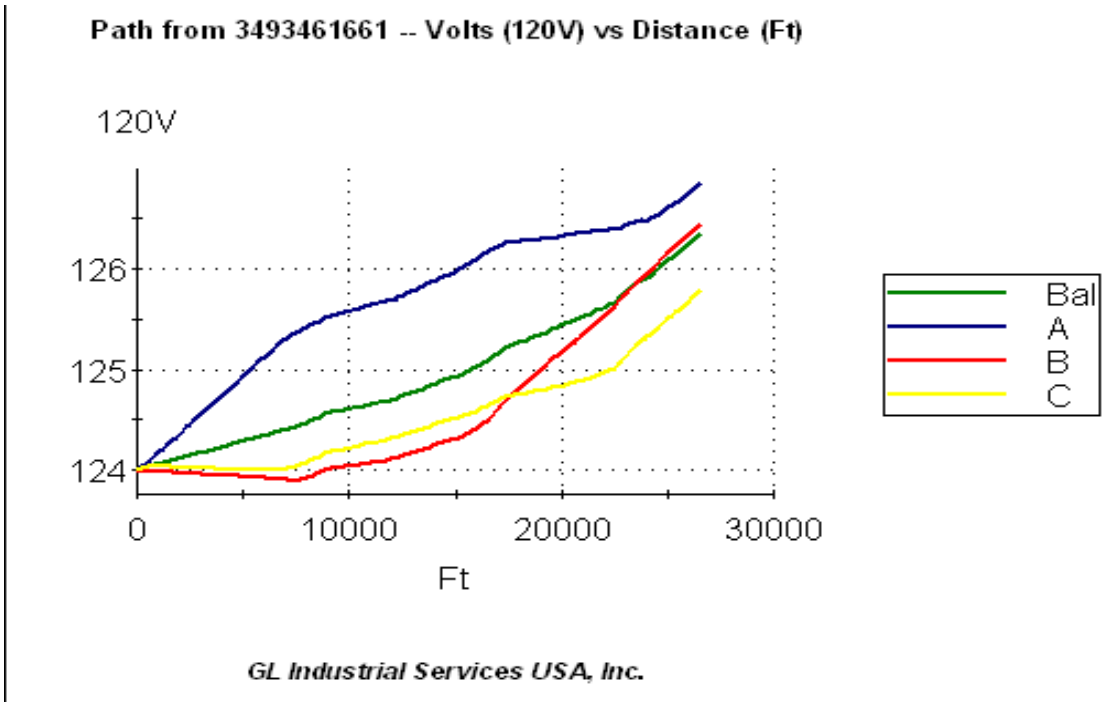
GL Industrial Services USA, Inc.

The model voltages at the point of interconnection are:

Phase A – 120.8 volts Phase B – 121.0 volts Phase C – 119.8 volts Balanced – 120.5 volts

The voltages on Alamogordo South Feeder 12-83 prior to the installation of Project Alamogordo Airport (Site 2) are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on all capacitor banks on Alamogordo South Feeder 12-83 (4200 kVAr total) energized.

Graph 5A - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport (Site 2) for daylight hours maximum load on June 5, 2010, 100% PF output

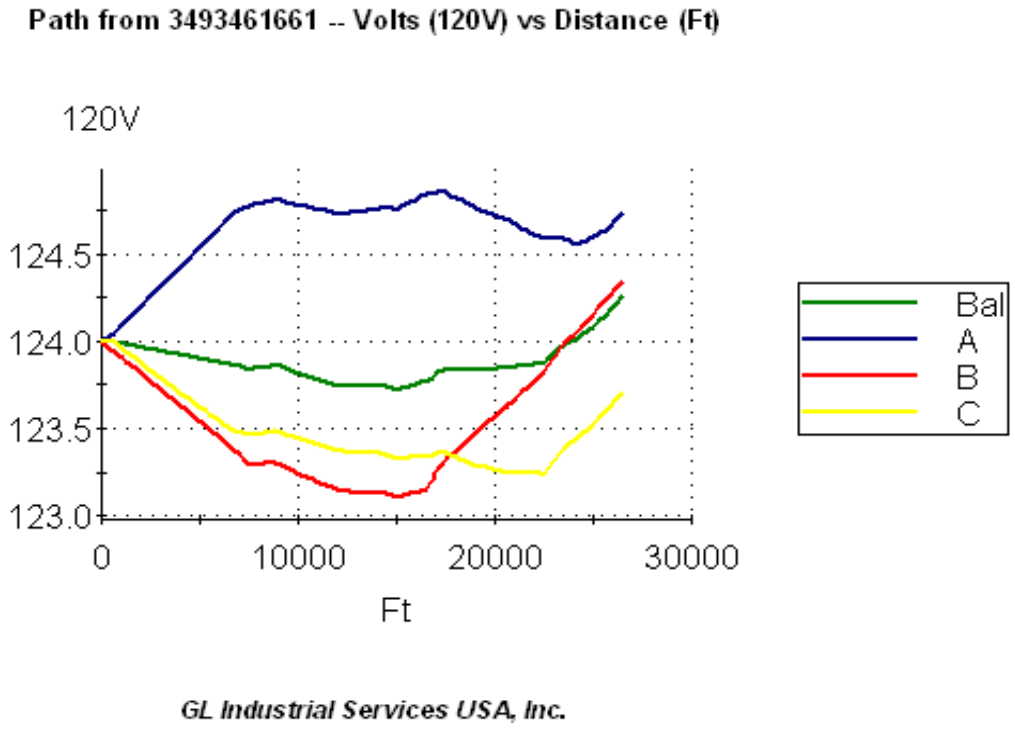


The model voltages at the point of interconnection are:

Phase A –126.9 volts Phase B – 126.4 volts Phase C – 125.8 volts Balanced – 126.4 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport (Site 2), at 100% PF output, are within PNM voltage criteria (ANSI C84.1) at the POI. This model is based on having all capacitor banks on Alamogordo South Feeder 12-83 energized. These capacitors provide 4200 kVAr total of reactive power on Alamogordo 12-83.

Graph 6A - Alamogordo South Feeder 12-83 voltage drop from Alamogordo South Substation to the POI with Project Alamogordo Airport (Site 2) for daylight hours maximum load on June 5, 2010, 99% lagging PF output



The model voltages at the point of interconnection are:

Phase A –124.7 volts Phase B – 124.3 volts Phase C – 123.7 volts Balanced – 124.3 volts

The voltages on Alamogordo South Feeder 12-83 after the installation of Project Alamogordo Airport (Site 2), at 99% lagging PF output, are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on having all capacitor banks on Alamogordo South Feeder 12-83 energized. These capacitors provide 4200 kVAr total of reactive power on Alamogordo 12-83.

Results show the impact Project Alamogordo Airport (Site 2) on Alamogordo South Feeder 12-83 without a three-phase voltage regulator and replacement of 2-600kVAR capacitor banks with a single switched 1200kVAR capacitor bank. If the Project is brought online, this equipment exchange is necessary to ensure voltage profiles stay within PNM criteria of ANSI C84.1.

In conclusion, Project Alamogordo Airport output does cause the voltage on Alamogordo South Feeder 12-83 to increase to unacceptable levels when allowed to operate at 100% PF.

Operating at 99% lagging PF allows the voltage to stay within the PNM criteria of ANSI C84.1 and is acceptable.

Review under contingency transfer was not conducted since feeder Alamogordo South 12-83, under any pertinent contingencies, is simply transferred using the substation bus tie breaker and therefore not necessary.

17.5 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Alamogordo South Feeder 12-83 has a voltage regulator installed on the feeder, upstream from Project Alamogordo Airport (Site 2). This addendum has modeled Alamogordo 12-83 without the three-phase voltage regulator. The substation LTC is set at 124 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 122.5 volts and will reduce the voltage if the substation bus is above 125.5 volts.

As seen in Tables 5A-8A, the SynerGEE modeling shows the LTC did not change position for a 6,000 kW source on the feeder for high or low load periods. This is not considered an adverse impact.

Project Alamogordo Airport (Site 2) was modeled as a source on Alamogordo South Substation connected to the end of Alamogordo South Feeder 12-83. The SynerGEE model included the substation transformer and Alamogordo South Feeders 12-83 and 12-89. The substation bus voltage and load tap changer position for maximum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport (Site 2), at a 99% lagging PF operation, per the SynerGEE model, are shown in Tables 5A and 6A.

Table 5A – ***Alamogordo South Substation with Project Alamogordo Airport (Site 2) OFF for daylight hours maximum load on July 14, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.2	124.1	124.1
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 5A. The voltages at Alamogordo South Substation prior to the installation of Project Alamogordo Airport (Site 2) are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 6A – ***Alamogordo South Substation with Project Alamogordo Airport (Site 2) ON at 99% lagging PF for daylight hours maximum load on July 14, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.2	124.3	124.3	124.3
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 6A. The voltages at Alamogordo South Substation after the installation of Project Alamogordo Airport (Site 2) are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The substation bus voltage and load tap changer position for minimum daylight hours load for August 1, 2009 through July 31, 2010 with and without Project Alamogordo Airport (Site 2) 6 MW, at a 99% lagging PF operation, per the SynerGEE model, are shown in Tables 7A and 8A.

Table 7A – ***Alamogordo South Substation with Project Alamogordo Airport (Site 2) OFF for daylight hours minimum load on April 18, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.1	124.1	124.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 7A. The voltages at Alamogordo South Substation prior to the installation of Project Alamogordo Airport (Site 2) are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8A – ***Alamogordo South Substation with Project Alamogordo Airport (Site 2) ON at 99% lagging PF for daylight hours minimum load on April 18, 2010***

	ALAMOGORDO SOUTH SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.1	124.1	124.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 8A. The voltages at Alamogordo South Substation after the installation of Project Alamogordo Airport (Site 2) are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Alamogordo South Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of Project Alamogordo Airport (Site 2) output.

17.6 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Alamogordo Airport (Site 2) POI is shown in Section 4.0. Table 9A summarizes the voltage and the calculated voltage flicker for the worst case phase. Table 10A is based on the GE flicker graph.

Table 9A - *Voltage flicker on Alamogordo South Feeder 12-83 due to Project Alamogordo Airport (Site 2) at -99% PF Output*

	POI Voltage Alamogordo South Feeder 12-83 Loading	
	Minimum (C-Phase)	**Maximum (A-Phase)**
Without Project	122.9	120.8
With Project	125.6	124.7
% Voltage Flicker	**2.19**	**3.23**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 10A - *Frequency of voltage flicker due to PV output changes*

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
2.19 (Min)	2/hour	30/hour
3.23 (Max)	Always Visible	10/hour

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 9A results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 10A. Distribution voltage flicker resulting from changes in Project Alamogordo Airport (Site 2) output is not anticipated to be an issue.

17.7 CONDUCTOR LOADING

Conductor loadings from the Project Alamogordo Airport (Site 2) POI to the substation were reviewed using the SynerGEE feeder model with and without Project Alamogordo Airport's maximum output of 6,000 kW AC.

There were no conductor loading problems from the POI to the substation on Alamogordo South Feeder 12-83 with Project Alamogordo Airport (Site 2) OFF. However, with Project Alamogordo Airport (Site 2) at maximum output, there were conductor loading problems. The estimate includes necessary line upgrade to 397 AAC conductor.

17.8 CAPACITORS

Switching capacitor banks on the PNM distribution system in Alamogordo are controlled by a time setting, temperature setting, or voltage setting. These settings vary from bank to bank in this area.

An inverter based grid connection will be a real power source (Watts only, no VArs) for the distribution system when operated at 100% PF. For this study, Project Alamogordo Airport (Site 2) was found to cause high voltages on the system for a 100% PF operation, so operation of 99% lagging PF is required. Regardless, when the inverter is operating and injecting watts, the power factor of the distribution feeder will appear to become worse.

Alamogordo South Feeder 12-83 has 4,200 total kVAr in capacitor banks (5x600 kVAr and 1x1200 kVAr). The June 2010 peak load on the feeder was estimated at 7,596 kW – j 478 kVAr or 7,611 kVA at a 99.8% leading power factor (i.e. 100.2% power factor). All capacitors were energized. Project Alamogordo Airport (Site 2) at a 5,940 kW + 846 kVAr AC output would change the apparent feeder loading to 1,656 kW + j 368 kVAr or 1,696 kVA at a 97.6% lagging power factor.

However, the amount of fixed capacitor banks during minimum loading causes voltages outside of PNM voltage criteria (ANSI C84.1) on Alamogordo 12-83. To compensate for the seasonal change, 2-600kVAr fixed capacitor banks must be replaced with one temperature controlled

switched 1200kVAr capacitor bank. This will ensure voltages are within specifications during both the minimum and maximum loading on Alamogordo 12-83.

Project Alamogordo Airport (Site 2) may cause a PF as low as 97.6% lagging on Alamogordo South Feeder 12-83, but no voltage issues were identified and the resulting new power factor would be acceptable.

17.9 PROTECTION

Alamogordo South Substation feeder 12-83 is protected by a 1200amp free standing breaker with three Westinghouse, CO-9 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO phase relays and one Westinghouse, CO residual ground relay. The transformer protection is three Westinghouse, HU-1 differential relays. The Project Alamogordo Airport (Site 2) PV system will be connected to the system approximately 5.08 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to a new three-phase Nova recloser. The available fault current at the recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Alamogordo Airport (Site 2) does not require any system protection improvements to be made to the Alamogordo South Substation feeder 12-83 under normal and contingency configuration.

17.10 FEEDER LOADING

No changes applied under Addendum (A) for Feeder Loading

17.11 METERING and COMMUNICATION

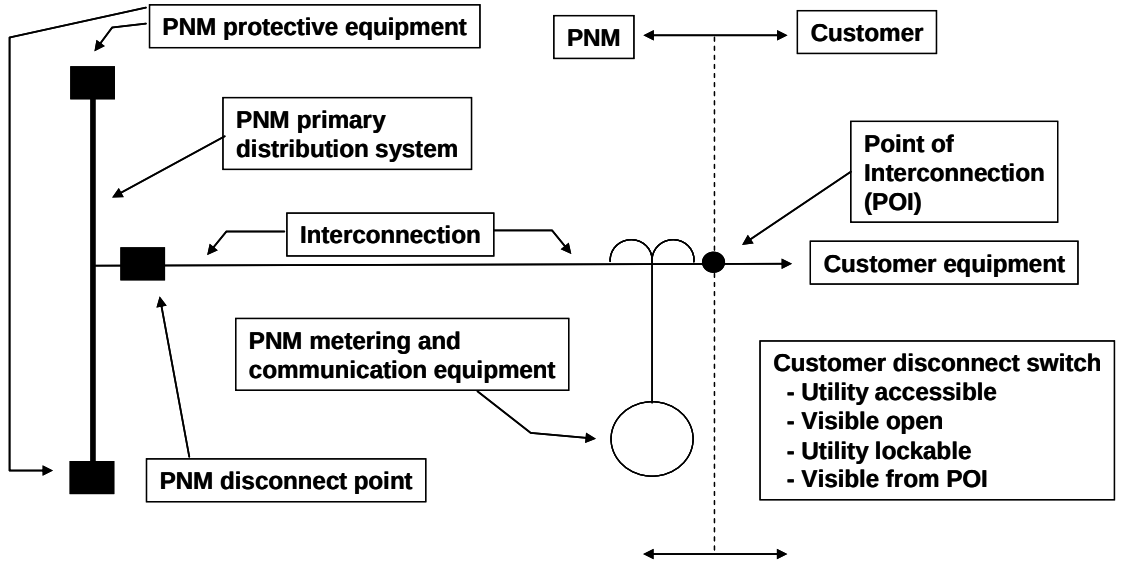
No changes applied under Addendum (A) for Metering & Communication

17.12 TYPICAL CONNECTION CONFIGURATION

Figure 3A is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3A ***– Typical Project Interconnection***

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

Project Alamogordo Airport (Site 2) to Alamogordo South Feeder 12-83 connection comprises:

- Approximately 1.37 miles of reconductor, approximately 1.07 miles of 1/0 ACSR and 0.30 miles of 2 ACSR, with 397 AAC conductor. (Figure 4A)
- Remove 1-600kVAR fixed capacitor bank from Pole#X96C012. (Figure 4A)
- Remove 1-600kVAR fixed capacitor bank from Pole#W97D019. (Figure 5A)
- Remove Voltage Regulator VR1305A from Pole#X96C174. (Figure 4A)
- Install 1-1200kVAR switched capacitor bank with temperature control on Pole#X96C012. (Figure 4A)
- Approximately .20 miles of new three-phase line with 397 AAC conductor. (Figure 6A)
- Install one S&C IntelliRupter switch. (Figure 6A)
- Install riser to primary meter, about 20 ft, using 750 AL. (Figure 6A)
- Install one PMH-9 gear on load side of primary meter, (load break operation).(Figure 6A)

Figure 4A *– Reconductor Sections, Equipment Removal/Install*

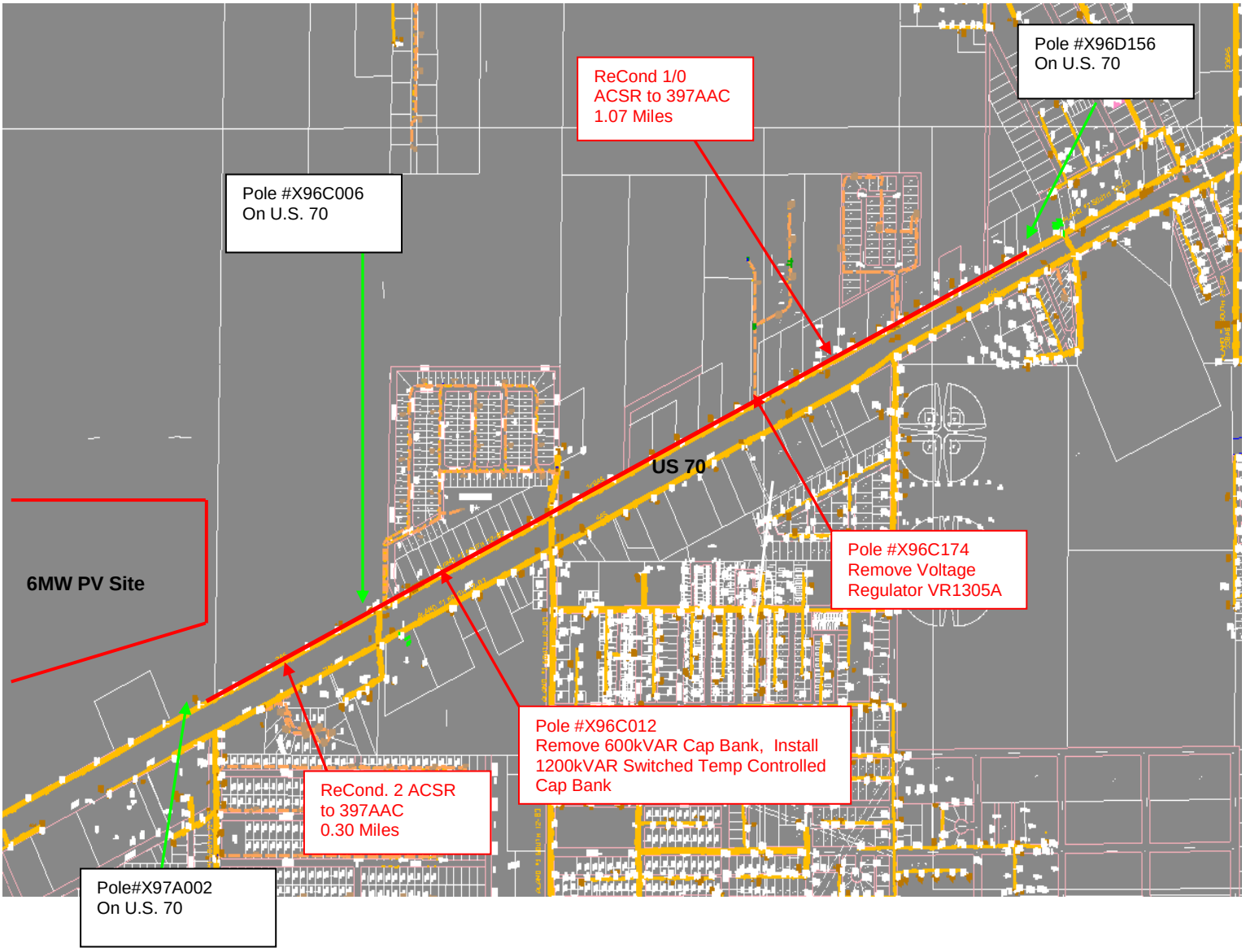


Figure 5A *– Equipment Removal*

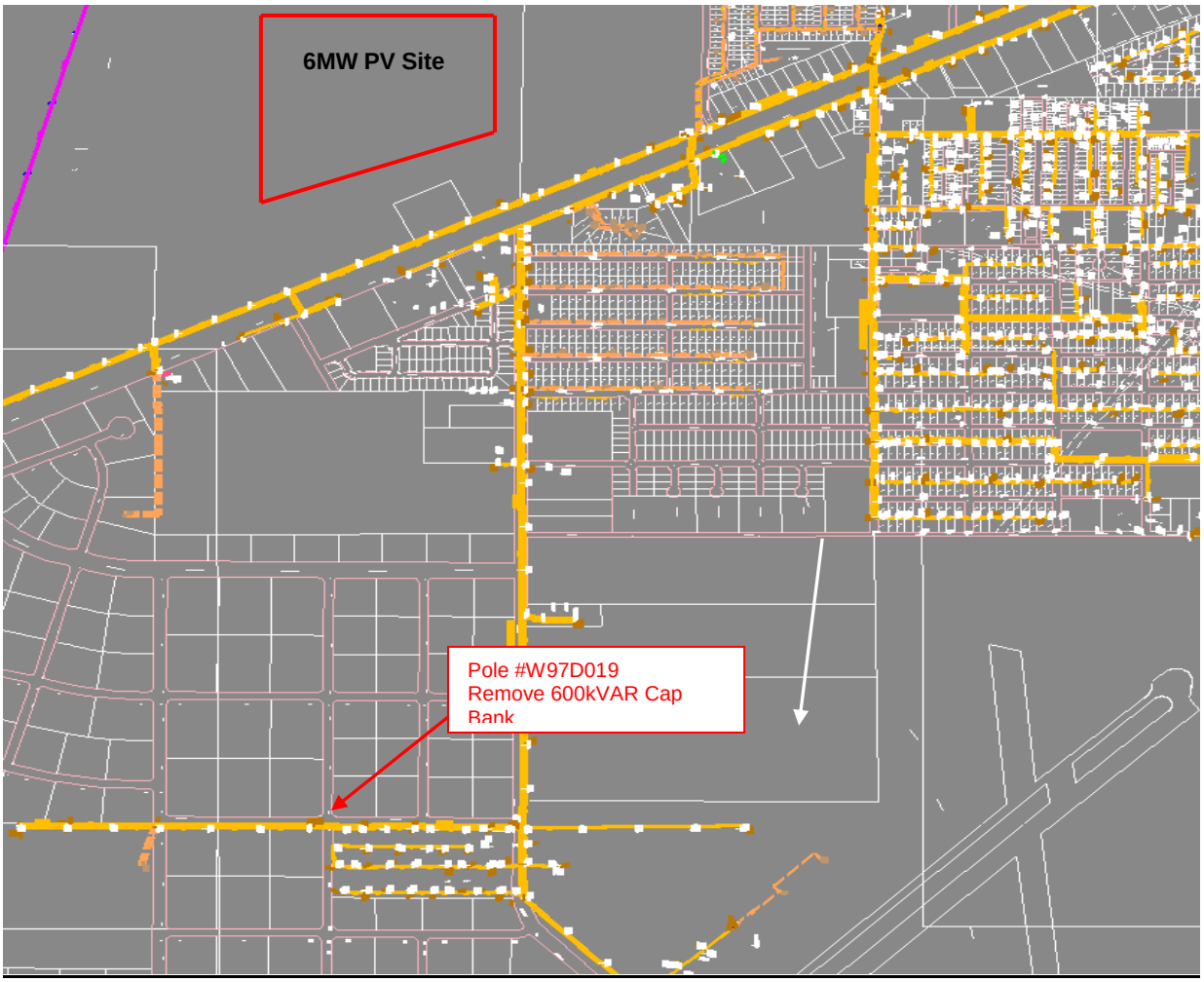
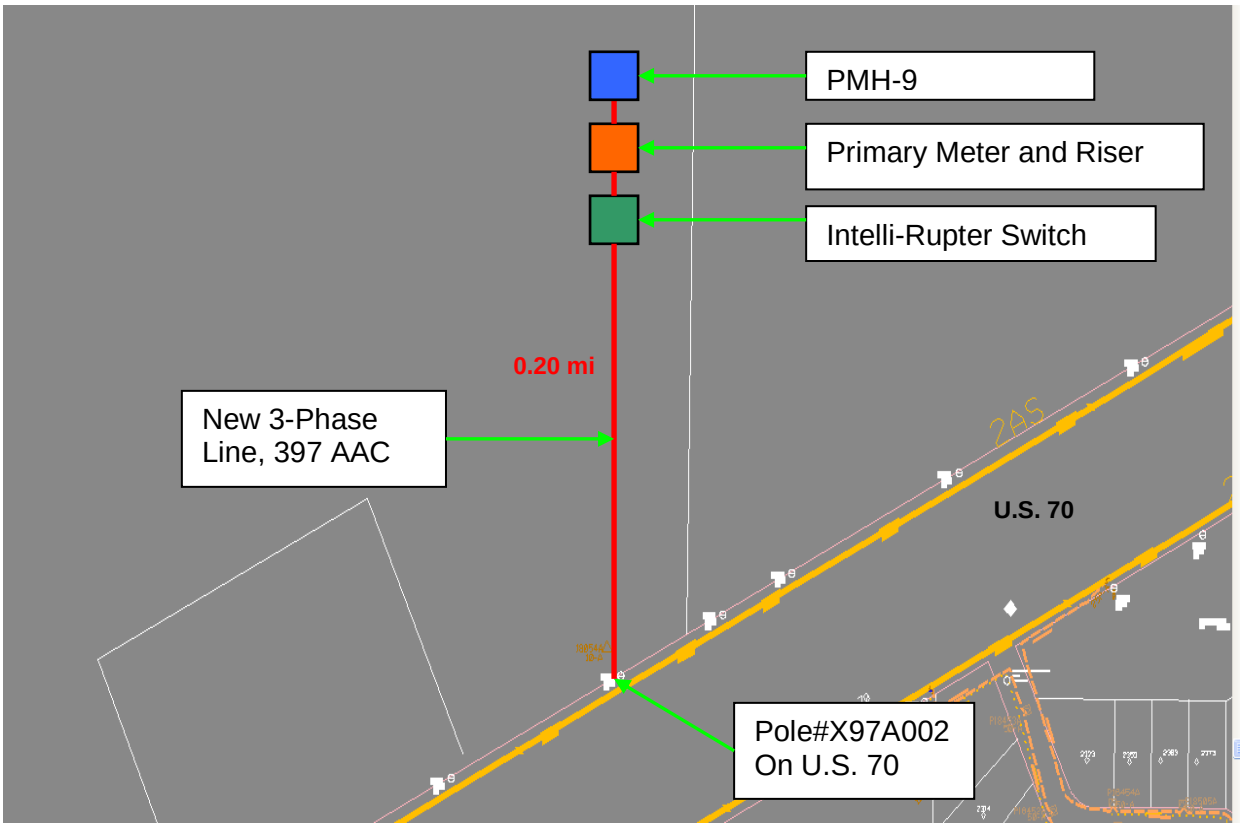


Figure 6A *– New Line Sections*



17.12 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 11A.

Table 11A ***- Project Alamogordo Airport (Site 2) Interconnection Cost***

	ESTIMATED COSTS 2011$	ESTIMATED CONSTRUCTION TIME
PNM disconnect point (IntelliRupter)	$ 41,853	~16 week lead time ~1 days construction
Interconnection (Line Construction)	$14,534	~2 week lead time ~2 days construction
System Upgrades	$215,509	~2 week lead time ~9.5 weeks construction
PNM Primary Metering	$ 64,606	~3 week lead time ~5 days construction
Communications	$ 45,000	~16 week lead time ~3 weeks construction
TOTAL	**$381,502**	

17.14 RIGHT-OF-WAY/EASEMENT ISSUES

No changes applied under Addendum (A) for Right-of-Way/Easement Issues

17.15 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

No changes applied under Addendum (A) for Facility Maintenance & Operation Agreements

17.16 CONCLUSIONS

Project Alamogordo Airport (Site 2) does have an adverse impact on the PNM distribution system when operating at 100% power factor. Voltage control is maintained by operating at a fixed power factor of 99% lagging. The Project location will result in an interconnection with Alamogordo South Feeder 12-83. When operating at a lagging 99% power factor, analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Fixed capacitor banks on the

feeder adversely impact voltages, 2-600 kVAr capacitor banks will need to be replaced with one temperature controlled switched 1200kVAr capacitor bank. A three-phase voltage regulator will need to be removed from Alamogordo Feeder 12-83. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will cause a slight flow of electricity from the distribution system through the substation transformer, the difference is less than 5 MW, and therefore no transmission voltage issues are anticipated. The necessary upgrades to three-phase lines to accommodate the Project will eliminate any conductor thermal issues. Finally, analysis shows that Project Alamogordo Airport (Site 2) output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Alamogordo Airport (Site 2) and has determined that there are no adverse impacts associated with a 6,000 KW AC source connected to Alamogordo South Feeder 12-83 when operated at a fixed lagging 99% PF.

Distribution Planning has determined that some system improvements are required to ensure that electric service to all customers on Alamogordo South Feeder 12-83 is maintained within established PNM voltage, equipment and fault protection criteria.

Public Service Company of New Mexico
Generation Planning and Development

Project Deming 6,000 KVA PV Generation Project

Small Generator Interconnection System Impact Study

(SGI-PNM-2010-10)

June 2011

Prepared by:

TRC Engineers, Inc.

Under Contract With:

Public Service Company of New Mexico

Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

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EXECUTIVE SUMMARY

Public Service Company of New Mexico Generation Planning and Development Department submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 6,000 KVA AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Deming and will be connected to Gold Feeder 11. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW. The Interconnection System Impact study was performed for Public Service Company of New Mexico Transmission/Distribution Planning and Contracts (Distribution Planning) by TRC Engineers, Inc. (TRC)

The estimated cost of connecting Project Deming to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ 61,000	~ 26 week lead time ~ 2 days to build
Interconnection**	$ 143,100	~ 1 week lead time ~ 21 days to build
PNM metering	$ 16,600	~ 16 week lead time ~ 4 days to build
Communication	$ 45,000	~16 week lead time ~3 weeks to build
TOTAL	**$ 265,700 Plus monthly O&M of $3,500.**	**6-7 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device.
** Reconductor and extend the distribution primary to the point of interconnection.

The application notes the use of a Sunny Central (SC) SMA 500CP inverter. The technical data notes for the SC SMA 500SC inverter were used to prepare this report. The data shows this inverter is presently not certified as UL 1741 complaint. The SC SMA 500SC inverter will have a 1,000V DC rating but is designed to meet UL 1741 anti-islanding, power factor and disturbance trip standards. Since UL testing is mostly limited to 600V systems the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer

technical data the inverter is capable of maintaining a unity power factor and this study assumed that the facility will maintain a unity power factor. Distribution Planning recommends the use of an inverter listed as UL 1741 complaint to insure, among other concerns, that the inverter will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other requirements as indicated in the SGIP application, Attachment 3. A complete field checkout witnessed and/or approved by PNM of the non-complaint equipment at the proposed facility is required before the facility can be considered certified for interconnection operation.

This system impact study evaluates the electrical system impacts for an interconnection request using an electric generation source connected to the PNM distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Deming does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Gold Feeder 11 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate as a result of the power produced by the Project, but did not have an adverse effect.
3. Project output variations due to clouds were found to not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. The one switched capacitor bank on the Gold Feeder 11 is not affected by Project Deming.
6. The Project contribution to fault current does not require the Gold Feeder 11, Gold Substation, Deming East Feeder 11 or Deming East Substation protection scheme be modified.
7. Project output will cause a flow of electricity from the distribution system through the Gold or Deming East Substation transformer. No transmission system related problems are anticipated to be associated with Project Deming.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Deming and has determined that there are no adverse impacts associated with a 6,000

KVA AC source operating at unity power factor connected to Gold Feeder 11 for the normal system configuration or to Deming East Feeder 11 for the contingent system configuration.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Gold Substation is maintained within established PNM voltage, equipment and fault protection criteria.

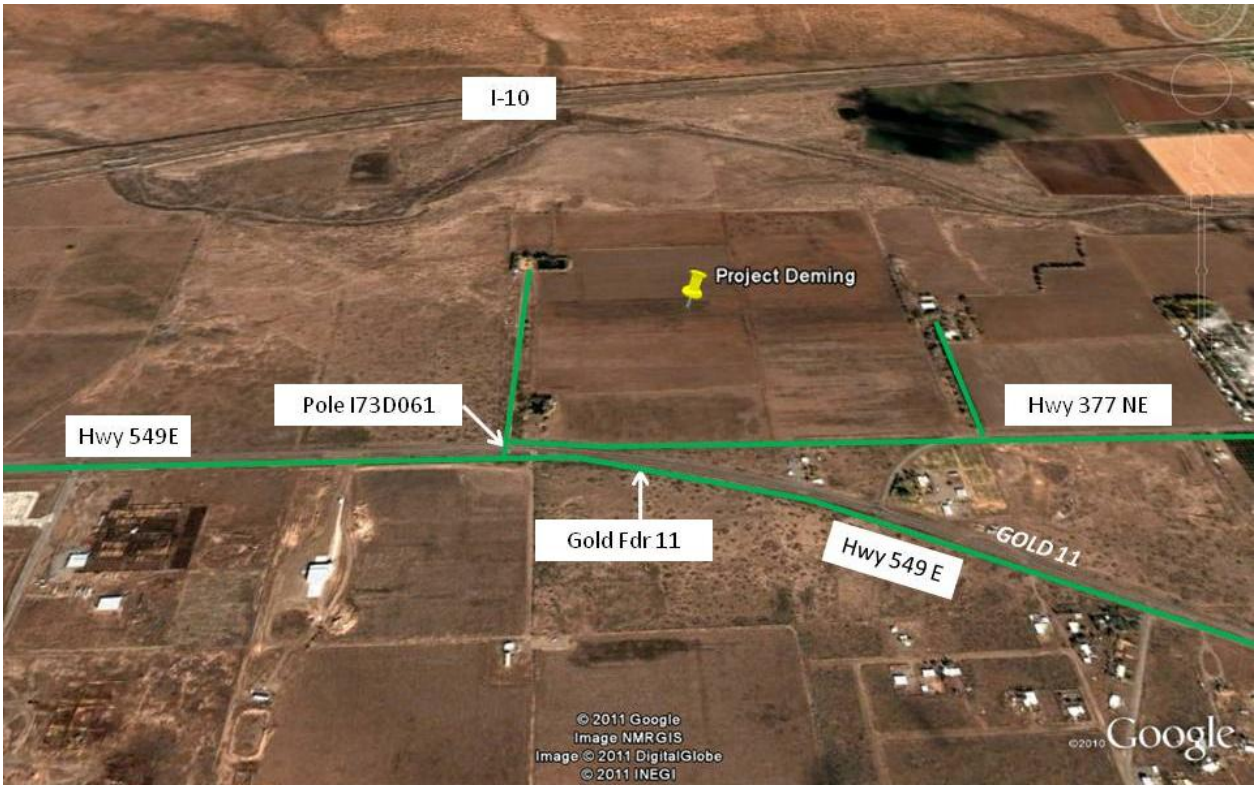
1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Deming. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage and current produced by the PV equipment to AC voltage and current. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Deming proposes to connect a 6,000 KVA AC PV facility to Gold Substation Feeder 11 in Deming, NM. The Project will be located north of the intersection of Hwy 549 SE and Hwy 377 NE in Deming as shown in Figure 1.

Figure 1 **– *Project Deming Location***



The circuit distance from Gold Substation to the Project Deming point of interconnection (POI) on Gold Feeder 11 is approximately 29,549 ft or 5.6 miles.

3.0 SYSTEM CONFIGURATION

Project Deming is connected to Gold Feeder 11 served from Gold Substation. Project Deming is normally served from Gold Feeder 11 with contingency backup provided by Deming East Feeder 11. Table 1 shows the rating of Gold and Deming East Substations as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate and Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating (kV)
		Normal	Emergency	
Gold	22.40	24.20	24.80	115-13.8
Deming East	9.38	9.38	10.30	115-13.8

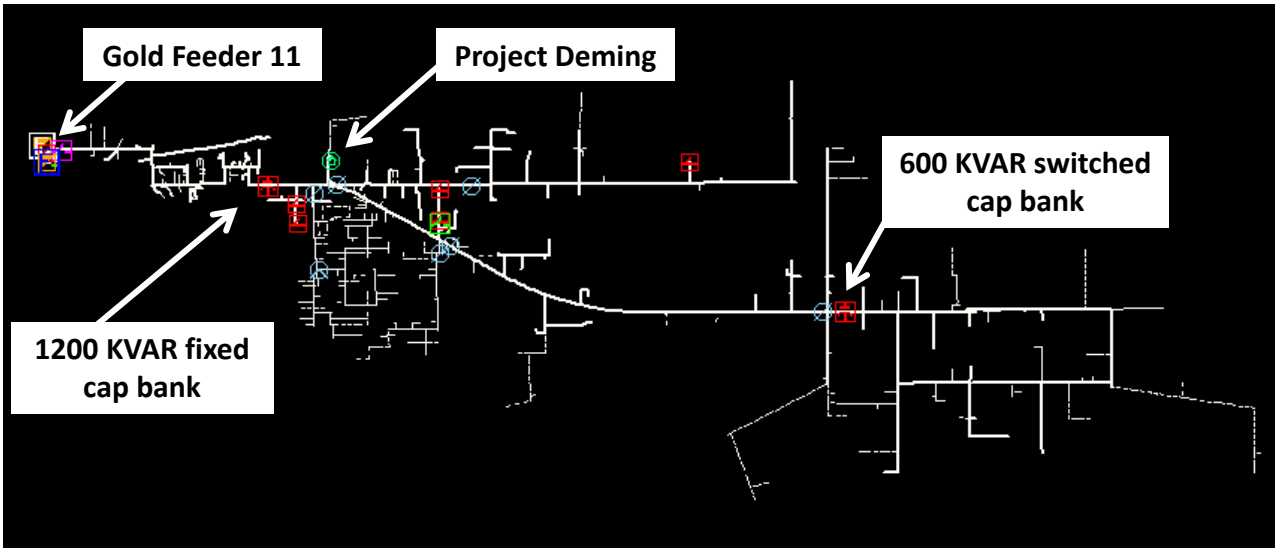
Table 2 shows the modeled non-coincident 2009 peak summer loads for Gold and Deming East Substation and feeders. The peak loads listed are individual peak loads and are non-coincident.

***Table 2* - Modeled July 2009 Non-coincident Peak Loads**

Feeder	July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Gold				
Gold 11	4,025	1,510	4,299	93.6
Gold Sub	8,800	3,390	9,430	93.3
Deming East				
Deming East 11	0	0	0	0
Deming East Sub	0	0	0	0

Figure 2 is a map of the SynerGEE model used for the study. In Figure 2 the bold solid lines represent three-phase portions of the feeder. Dashed lines represent single phase portions of the circuit.

Figure 2 – Synergee model of Gold 11



System improvements to address existing voltage problems on Gold Feeder 11 including an increase of the feeder nominal source feeder voltage to 123 V in the future are included in this impact study. Initial modeling of Gold Feeder 11 revealed possible voltage issues. Resolution of the voltage issues are outside the scope of this impact study. For the purpose of this impact study, improving the voltage at the POI to be within ANSI C84.1 Range A consisted of two items. The first is to increase the fixed capacitor bank to 1,200 KVAR and the second is to increase the Gold Substation to 123 V. Final system improvement recommendations are not expected to materially affect the conclusions of this impact study.

Gold Feeder 11 was modeled with one fixed 1,200 KVAR capacitor and one switched 600 KVAR capacitor. The capacitors on Gold Feeder 11 were modeled as being on-line for the maximum load conditions addressed in this study. The capacitor C918D on Gold Feeder 11 was modeled as being on-line while the switched capacitor C927D was off-line for the minimum load conditions addressed in this study. Deming East Feeder 11 has no capacitors. The status of the capacitors is shown in Table 3.

Table 3 - Status of Capacitors

Capacitor	KVAR Size	Fixed or Switched	Status	
			Min load	Max Load
Gold 11				
C918D	1,200	F	ON	ON
C927D	600	S	OFF	ON
Deming East 11				
None	-	-	-	-

NOTE: Capacitor bank C918D is presently a 600 KVAR bank fixed bank which will be upgraded to a 1,200 KVAR bank.

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours – the first condition is the peak load on each study area distribution circuit and the second condition is the minimum load on each study area distribution circuit. The times for maximum and minimum load are non-coincident for the distribution circuits. The daylight hour time ranges (Mountain Time zone) for each month shown in Table 4 is used to identify the maximum and minimum loads to be modeled in a PV system impact study.

Table 4 - Time range for PV studies

Time Range for PV Studies		
7 AM - 7 PM	**8 AM – 5 PM**	**8 AM – 4 PM**
April	March	January
May	September	February
June	October	November
July		December
August		

The modeled maximum and minimum daylight hours loading on the Gold Feeder 11 and Deming East Feeder 11 are shown in Table 5:

Table 5 - Modeled max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Gold 11								
July 9, 2009	3 PM	4,025	1,510	4,299	93.6	159	154	217
Sept 20, 2009	8 AM	1,410	400	1,465	96.2	53	55	77
Deming East 11								
N/A*		0	0	0	0	0	0	0
N/A*		0	0	0	0	0	0	0

* Deming East Feeder 11 is normally unloaded.

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but the power flow analyses assumes maximum PV system output.

Project Deming at its maximum production capability output, exceeds the load on the Gold Substation transformer during minimum load periods. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system. Table 6 shows the maximum and minimum load on the Gold Substation transformer.

Table 6 - Gold Substation max/min Daylight Hours Load

	KW	KVAR	KVA	Power Factor
Maximum	8,800	3,390	9,430	93.3
Minimum	1,550	310	1,581	98.1

4.1 Voltage impacts on the transmission system

Project Deming will be injecting 6,000 KVA into the distribution system at the POI. The minimum load on Gold Substation will be lower than the Project rated output which will result in a flow of power through the substation transformer into the transmission system. Since this is less than PNM's threshold of 5 MW over the transformers minimum load, no transmission system related problems are anticipated to be associated with Project Deming at maximum or minimum output.

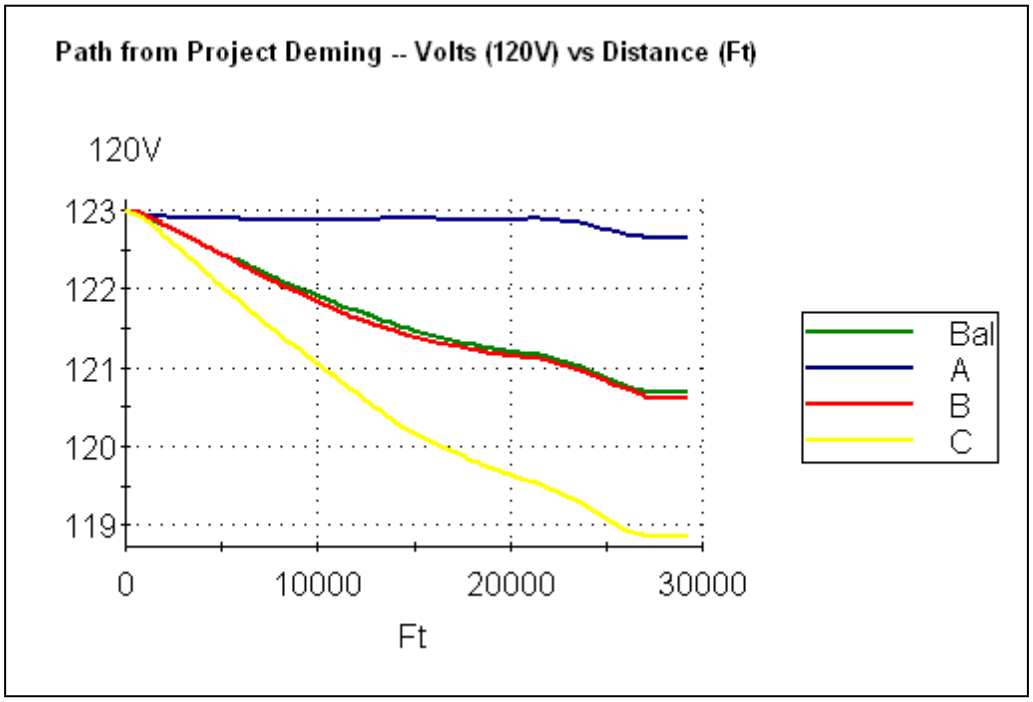
4.2 Screen for PV system impacts associated with power factor setting

The electric distribution system was screened to determine if there are any adverse impacts associated with Project Deming injecting energy into Gold Feeder 11. The capacitor status shown in Table 3 was used to evaluate the electric distribution system. Project Deming was evaluated operating at a 100% power factor to determine if system operating criteria limits were violated. The utility system was evaluated with and without Project Deming for maximum and minimum feeder loads during normal and contingent configurations. The evaluation with Project Deming operating at 100% power factor for maximum and minimum load during normal and contingency conditions shows that the distribution system voltages are within the ANSI C84.1 criteria and is acceptable.

4.3 Voltage impacts for maximum daylight hour loads under normal configuration

The Gold Feeder 11 voltages for the feeder daylight hour maximum load in 2009 with and without Project Deming, per the SynerGEE model, are shown in Graphs 1 and 2.

Graph 1 – Gold Feeder 11 voltage profile from Gold Substation to Project Deming POI for the daylight hour maximum load. Project Deming is OFF.

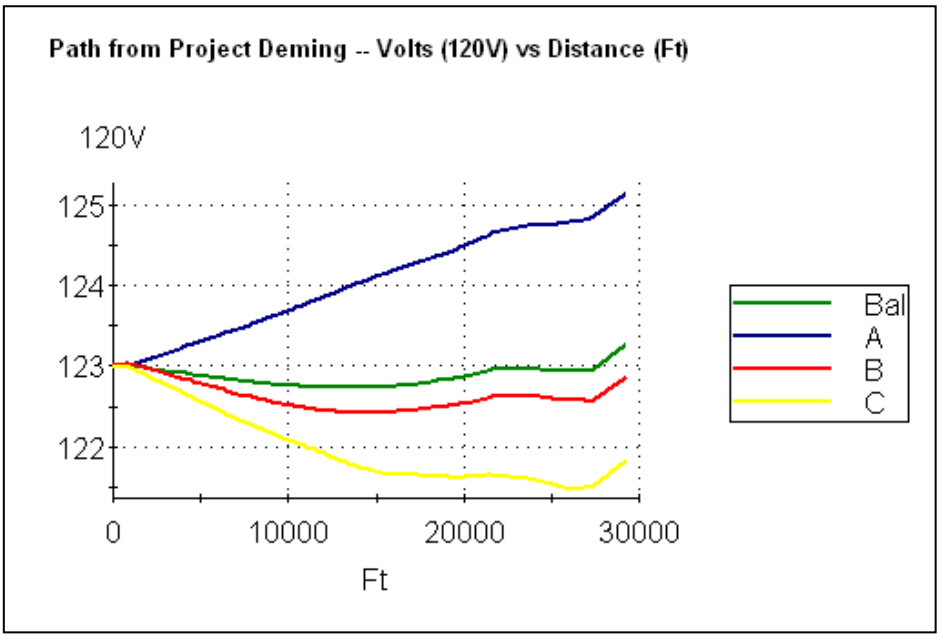


The model voltages at the point of interconnection are:

Phase A – 122.6 volts Phase B – 120.6 volts Phase C – 118.9 volts Balanced – 120.7 volts

The voltages on Gold Feeder 11 prior to the installation of Project Deming are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 - Gold Feeder 11 voltage profile from Gold Substation to Project Deming POI for daylight hour maximum load. Project Deming is ON



The model voltages at the point of interconnection are:

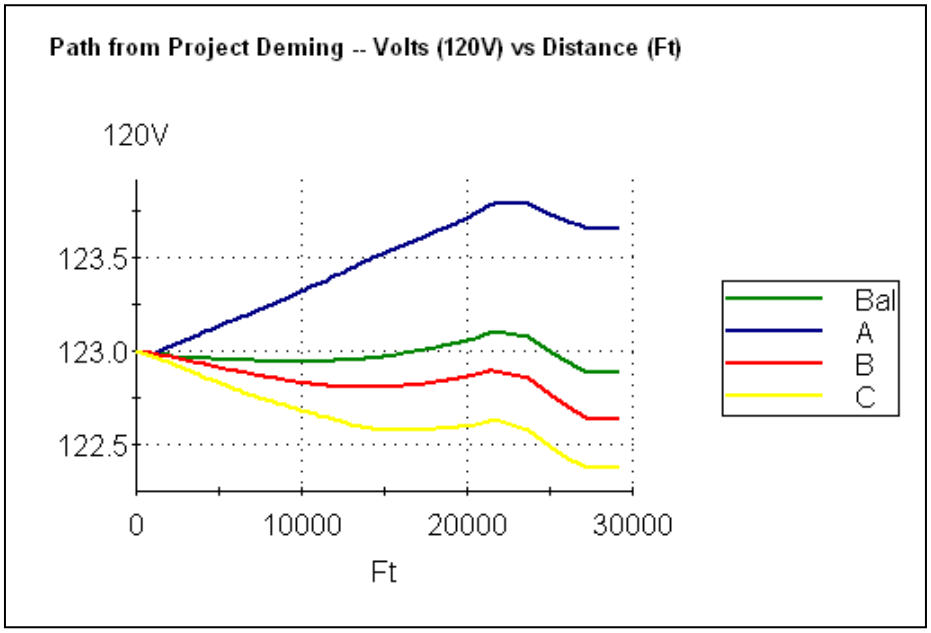
Phase A – 125.1 volts Phase B – 122.9 volts Phase C – 121.8 volts Balanced – 123.3 volts

The voltages on Gold Feeder 11 after the installation of Project Deming are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4 Voltage impacts for minimum daylight hour loads under normal configuration

The Gold Feeder 11 voltages for the feeder daylight hour minimum load in 2009 with and without Project Deming, per the SynerGEE model, are shown in Graphs 3 and 4.

Graph 3 - Gold Feeder 11 voltage profile from Gold Substation to Project Deming POI for daylight hour minimum load. Project Deming is OFF.

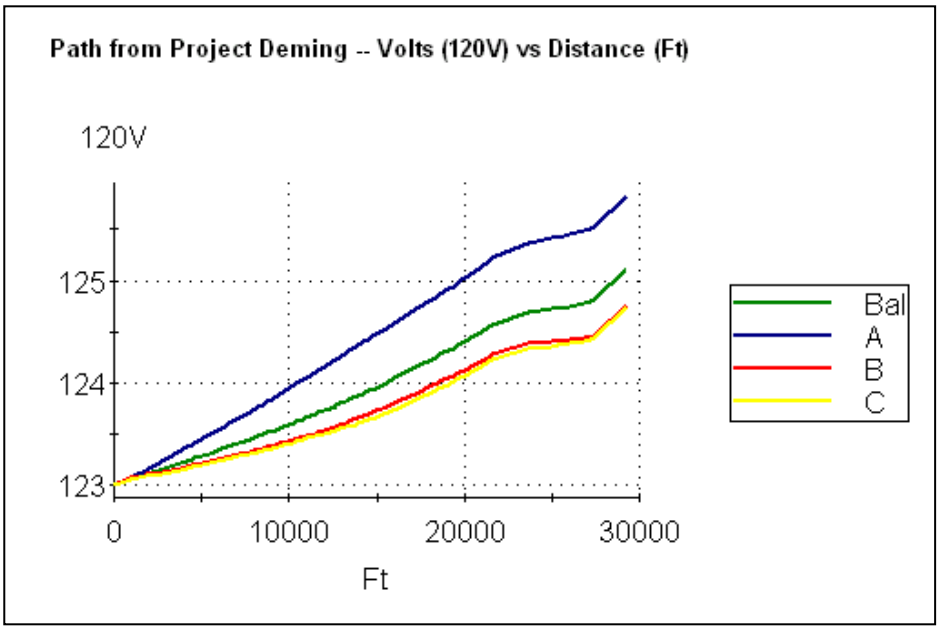


The model voltages at the point of interconnection are:

Phase A – 123.7 volts Phase B – 122.6 volts Phase C – 122.4 volts Balanced – 122.9 Volts.

The voltages on Gold Feeder 11 prior to the installation of Project Deming are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 - Gold Feeder 11 voltage profile from Gold Substation to Project Deming POI for daylight hour minimum load. Project Deming is ON



The model voltages at the point of interconnection are:

Phase A – 125.8 volts Phase B – 124.8 volts Phase C – 124.7 volts Balanced – 125.1 volts.

The voltages on Gold Feeder 11 after the installation of Project Deming are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

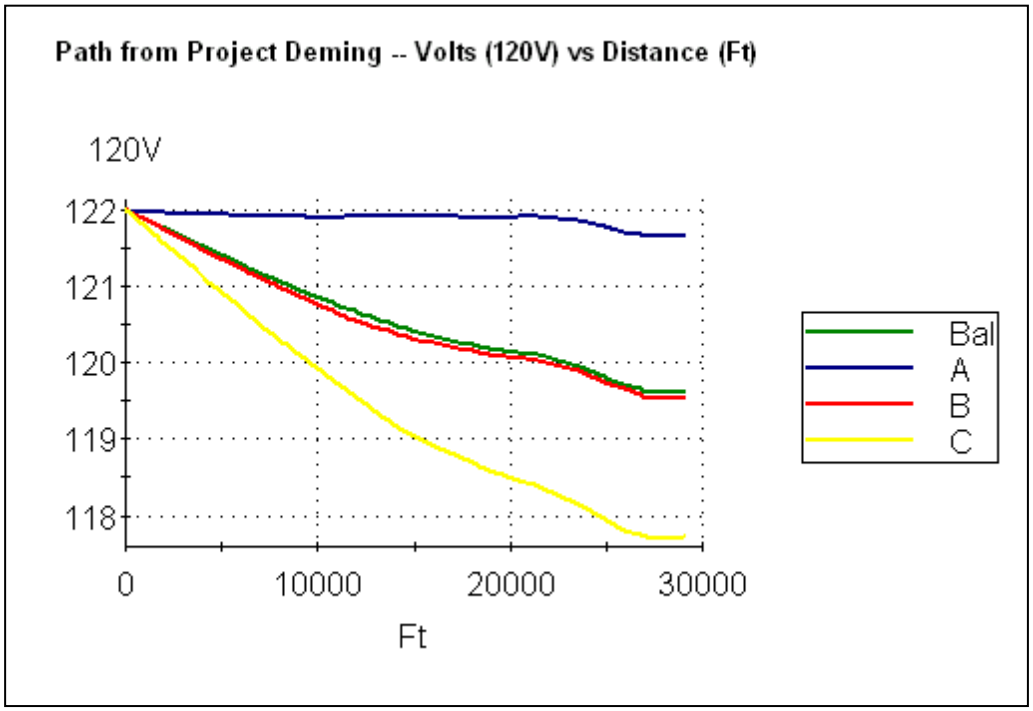
4.5 Voltage impacts during an outage of Gold Substation

Deming East Feeder 11 backs up Gold Feeder 11 when Gold Substation is out-of-service. The minimum and maximum loads on Deming East Feeder 11 and Gold Feeder 11 for the daylight hours are shown in Table 4. For the condition of Gold Substation out-of-service, 100% of Gold Feeder 11 is transferred to Deming East Feeder 11.

4.5.1 Voltage impacts for daylight hour maximum load during an outage of Gold Substation

The Deming East Feeder 11 voltages for daylight hour maximum load for 2009 with and without Project Deming, per the SynerGEE model, are shown in Graphs 5 and 6

Graph 5 – Deming East Feeder 11 voltage profile from Deming East Substation to Project Deming POI for the loss of Gold Substation for daylight hour maximum load. Project Deming is OFF.

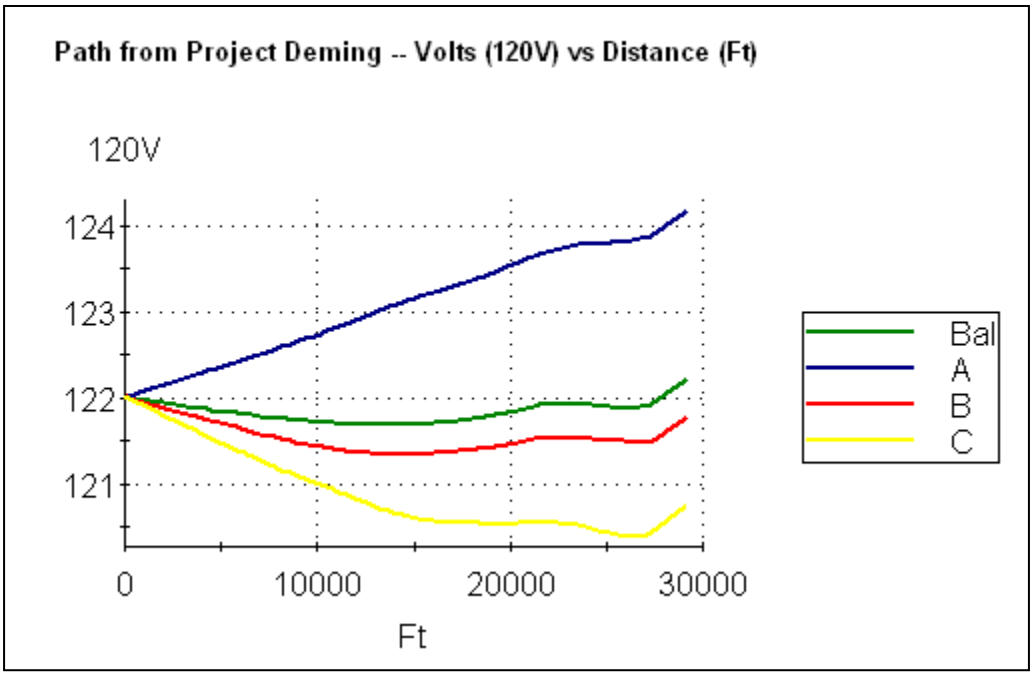


The model voltages at the point of interconnection are:

Phase A – 121.7 volts Phase B – 119.5 volts Phase C – 117.7 volts Balanced – 119.6 volts

The voltages on Deming East Feeder 11 for the loss of Gold Substation prior to the installation of Project Deming are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 6 – Deming East Feeder 11 voltage profile from Deming East Substation to Project Deming POI for the loss of Gold Substation for daylight hour maximum load. Project Deming is ON.



The model voltages at the point of interconnection are:

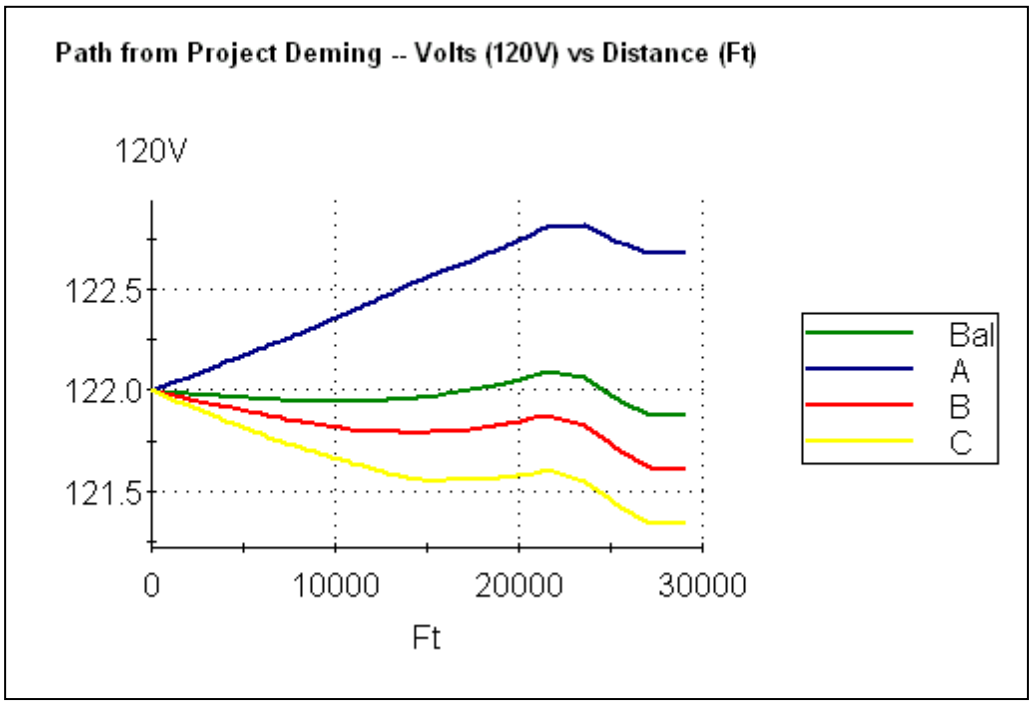
Phase A – 124.2 volts Phase B – 121.8 volts Phase C – 120.7 volts Balanced – 122.2 volts

The voltages on Deming East Feeder 11 for the loss of Gold Substation contingency after the installation of Project Deming are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5.2 Voltage impacts for daylight hour minimum loads during an outage of Gold Substation

The Deming East Feeder 11 voltages for daylight hour minimum load for 2009 with and without Project Deming, per the SynerGEE model, are shown in Graphs 7 and 8.

Graph 7 - Deming East Feeder 11 voltage profile from Deming East Substation to Project Deming POI for the loss of Gold Substation for daylight hour minimum load. Project Deming is OFF.

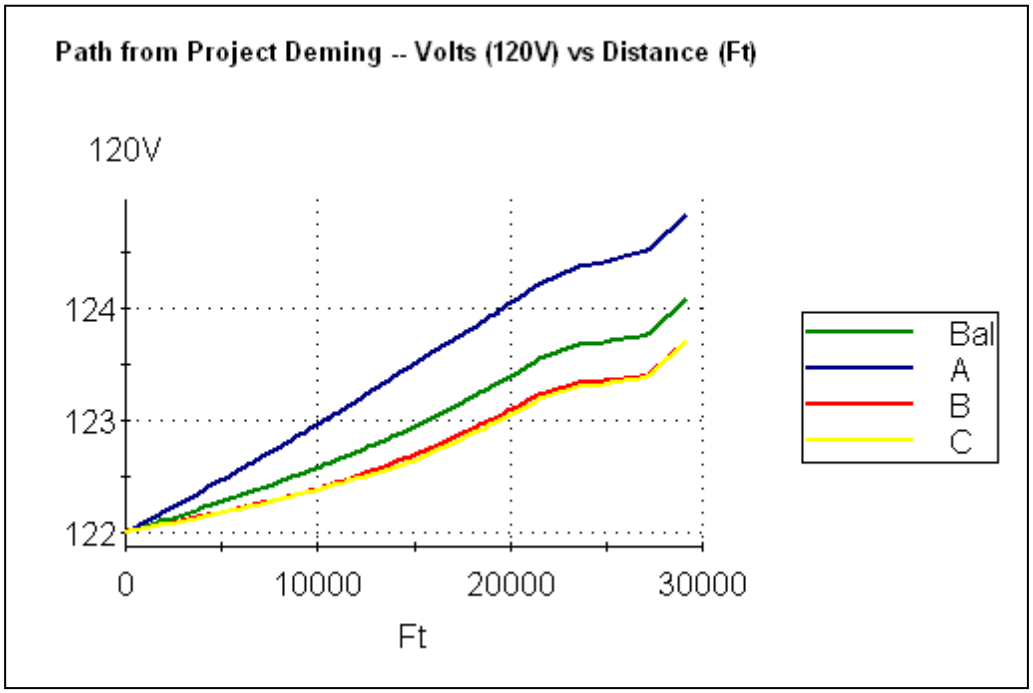


The model voltages at the point of interconnection are:

Phase A – 122.7 volts Phase B – 121.6 volts Phase C – 121.3 volts Balanced – 121.9 volts

The voltages on Deming East Feeder 11 for the loss of Gold Substation contingency prior to the installation of Project Deming are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 8 - Deming East Feeder 11 voltage profile from Deming East Substation to Project Deming POI for the loss of Gold Substation for daylight hour minimum load. Project Deming is ON.



The model voltages at the point of interconnection are:

Phase A – 124.8 volts Phase B – 123.7 volts Phase C – 123.7 volts Balanced – 124.1 volts

The voltages on Deming East Feeder 11 for the loss of Gold Substation contingency after the installation of Project Deming are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion, the output from Project Deming does cause the voltages on Deming East Feeder 11 for the contingency configuration to increase. However, the voltages stay within the PNM criteria of ANSI C84.1 and are acceptable.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is accomplished by a combination of either of two methods. The first method is to employ a step voltage regulator located at either the substation

or some distance from the substation along the feeder route. The voltage regulation by a step voltage regulator can be accomplished by using either a load tap changer [“LTC”] on the substation transformer or by installing a voltage regulator out on the distribution feeder. The second commonly employed method of voltage control on distribution feeders is the use of shunt capacitors installed along the feeder route. The impact of the Project Deming on capacitor voltage control is discussed in Section 8 Capacitors.

Project Deming is normally served by Gold Feeder 11 and the backup source is Deming East Feeder11. There are no voltage regulators installed on either feeder. The Gold Substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

Project Deming was modeled as a 6,000 KVA at unity power factor on Gold Substation connected to Gold Feeder 11. The SynerGEE model included the substation transformer and Gold Feeder 11. The substation bus voltage and load tap changer position results from the SynerGEE model for maximum daylight hour feeder loads for 2009 with and without Project Deming are shown in Tables 7 and 8.

As seen in Tables 7 – 10, the SynerGEE modeling shows the LTC did not change positions with the 6,000 KVA Project Deming resource on the feeder for either high or low load periods.

Table 7 ***- Gold Substation with Project Deming OFF for daylight hour maximum load.***

	GOLD SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.4	122.5	122.0	122.3
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 7. The voltages at Gold Substation prior to the installation of Project Deming are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8 ***- Gold Substation with Project Deming ON, 100% power factor for daylight hour maximum load.***

	GOLDSUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.5	122.4	122.3	122.4
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 8. The voltages at Gold Substation with Project Deming ON are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Gold Feeder 11 voltages for the minimum daylight hour load in 2009 with and without Project Deming, per the SynerGEE model, are shown in Tables 9 and 10.

Table 9 ***- Gold Substation with Project Deming OFF for daylight hour minimum load.***

	GOLD SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	123.2	123.2	123.1	123.2
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 9. The voltages at Gold Substation prior to the installation of Project Deming are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 10 – Gold Substation with Project Deming ON, 100% power factor for daylight hour minimum load.

	GOLD SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.9	122.9	122.9	122.9
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 10. The voltages at Gold Substation with Project Deming ON are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The voltage on Gold Substation bus stayed within the PNM criteria of ANSI C84.1 for both daylight hours maximum and minimum load conditions regardless of Project Deming output. There is a small variation in the voltages with Project Deming producing power versus the voltage without Project Deming. These voltage variations might be significant enough to trigger an operation of the tap changer to operate. However, the output of Project Deming is deemed to not have an adverse impact on the Gold Substation LTC or bus system voltage regulation.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company [“GE”] developed a graph showing fluctuations per time period versus borderline of visibility and borderline of irritation. PNM’s operating criteria are that the magnitude of voltage flicker must be limited to less than 6% and that the frequency of flicker fluctuations be less than the border line of irritation boundary shown in the GE Flicker Limit Curve.[i]

Clouds shading the PV panels adversely impact the output of a PV system. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be

seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting.

A rapid change in load cannot be compensated by the voltage regulation equipment installed on a distribution system. PNM has a time delay setting of 30 seconds for its substation LTCs and line voltage regulators. This time delay means that an LTC or voltage regulator will not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known, the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the duration of a voltage dip due to the starting of an electric motor.

The voltage at the Gold Substation bus was fixed at 123 volts with and without Project Deming output for maximum and minimum load periods. Table 11 summarizes the balanced voltage and the calculated voltage flicker magnitude. Project output will exhibit relatively slow variations due to cloud cover shading rather than spike between full on and off. Consequently the results shown in Table 11 represent a worst-case scenario.

Table 11 ***- Voltage flicker at the POI due to Project Deming***

	Project Deming POI Bus Voltage	
	Minimum	**Maximum**
Without Project	122.9	120.7
With Project	125.1	123.3
% Voltage Flicker	**1.79**	**2.15**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 12 is based on an interpolation of the flicker frequency from the GE flicker graph. For a 2% flicker magnitude the frequency of voltages fluctuations would need to be on the order of 1 fluctuation per minute to approach the borderline of irritation limit. Cloud movement is slow thus voltage flicker frequency of fluctuations will be less than the frequency limits shown in Table 12. The calculated magnitude of the flicker due to the Project Deming is much less than PNM's 6% limit criterion. The distribution voltage flicker resulting from changes in Project Deming output is not anticipated to have an adverse effect.

Table 12 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	Border Line of Irritation
1.79	3/hour	1/minute
2.15	2/hour	1/minute

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Deming to the substation were reviewed using the SynerGEE feeder model with and without Project Deming maximum output of 6,000 KVA AC.

There were no conductor loading problems from the POI to the substation on Gold Feeder 11 or Deming East Feeder 11 with or without Project Deming.

8.0 CAPACITORS

The capacitor banks on Gold Feeder 11 are fixed banks and switched banks with local adaptive controls only. The capacitor banks on Gold Feeder 11 are not controlled by the Radio Control Central Station (RCCS) program.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no VARs. When the inverter is operating the power factor of the distribution feeder as measured at the substation, will appear to become worse.

Gold Feeder 11 was modeled with one 1,200 KVAR fixed capacitor bank and one switched 600 KVAR capacitor bank, which is the assumed feeder configuration that will be in place before Project Deming is in-service. The modeled July 2009 peak load on the feeder, with Project Deming OFF, was 4,072 KW + j 879 KVAR or 4,166 KVA at a 97.7 lagging power factor. Both the 1,200 and 600 KVAR capacitor banks were assumed to be energized during the peak load period. The modeled July 2009 peak load on the feeder, with Project Deming ON would change the apparent feeder loading to -1,869 KW + j 824 KVAR or 2,043 KVA at 91.5% lagging power factor. The KVAR difference in the modeled feeder loading is due to the change in the feeder voltage profile and its effect on the feeder capacitors. The lagging power factor seen by Gold Substation has decreased, but will not affect the capacitor status on the feeder as all capacitor banks are already energized. Note that the Gold Feeder 11 with Project Deming ON will be injecting real power into the Gold Substation and absorbing reactive power from Gold Substation.

The capacitor bank status for minimum load conditions was also studied to see what affect this would have on the system. At minimum feeder load, the 1,200 KVAR fixed capacitor bank is energized and the switched 600 KVAR capacitor bank is OFF. The 600 KVAR switched capacitor bank is not affected by Project Deming. The voltage on the feeder is within the PNM voltage criteria (ANSI C84.1) at the POI and is acceptable.

For the loss of Gold Substation, Deming East 11 provides backup support to Gold Feeder 11. Deming East 11 has no capacitor banks and the contingency analysis shows that with both banks energized the feeder voltages are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable for this configuration.

9.0 PROTECTION

9.1 Normal Configuration – Service from Gold Feeder 11

Gold Feeder 11 is protected from overcurrents by a 1,200 amp breaker in metal clad switchgear. An ABB DPU2000R relay provides phase overcurrent and residual ground overcurrent detection as well as recloser timing intervals. A DPU 2000R relay also provides switchgear bus and feeder backup protection. Gold Substation transformer protection is provided by an ABB TPU2000R differential relay.

Fault analyses were conducted for the normal service configuration of Gold Feeder 11 to determine the impact of Project Deming's interconnection on Gold Feeder 11's protective devices. The Project was modeled in SynerGEE to produce the 2,250 amps of fault current at 270V for each 500 KVA inverter as noted on the SGIP application form. The SynerGEE model of the 6,000 KVA Project Deming PV plant provided a total of 27,000 A of fault current at 270 V for the fault analyses. Project Deming was modeled as connected to the distribution primary system approximately 29,260 circuit feet from Gold Substation on Feeder 11. There are seven hydraulic reclosers on Gold Feeder 11, the closest is ~0.5 miles from Project Deming and the farthest is ~7.8 miles from Project Deming.

The fault analysis first considered end of circuit faults. Generation installed between a recloser or substation breaker and a fault location masks a portion of the fault current from the upstream protective device. This masking, in effect, desensitizes the protective device. The fault analysis shows that the fault contribution of Project Deming will not interfere with the proper operation of the substation relay and breaker for an end of circuit fault when the feeder is in its normal configuration.

The fault conditions evaluated next were the impact to the reclosers. The fault analysis shows that the available fault current at each recloser, for faults on the system anywhere on the load-side of the reclosers, is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The fault interrupt rating was evaluated for each recloser for a fault immediately downstream of the recloser. The fault analysis shows all reclosers have adequate interrupt ratings for faults downstream of the recloser.

The impact of Project Deming's fault contribution to sectionalizer coordination was evaluated. The fault analysis shows that the fault contribution of Project Deming will not interfere with the proper coordination of the sectionalizer with reclosers and substation relays.

The impact of Project Deming's fault contribution to fuse coordination was also evaluated. The fault analysis shows that the fault contribution of Project Deming will not interfere with the proper coordination of the installed tap line fuses with the substation relays.

The fault analyses also evaluated the impact of Project Deming on faults close to the substation breaker. For faults on adjacent feeders that are close to the substation or for bus faults the generator's fault current contribution could cause the Gold Feeder 11 breaker to open. An unintended feeder breaker operation for a bus fault or for a fault on an adjacent feeder is considered to be a miscoordination of the feeder's breaker and relay device protective scheme. Fault analysis shows that that the fault current contribution from Project Deming exceeds the minimum pickup current value for the Gold Feeder 11 relay for faults close to the substation. However, the magnitude of the fault contribution from Project Deming is sufficiently less than the total fault current that the bus and adjacent feeder relays and breakers will clear a close-in fault within their zones of protection before the Gold Feeder 11 breaker will operate.

Project Deming does not require any system protection improvements to be made to the Gold Feeder 11 under normal configuration to correct coordination problems.

9.2 Contingency Configuration – Deming East Feeder 11 Picks Up Gold Feeder 11 for an Outage of Gold Substation

For an outage of Gold Substation, Deming East Feeder 11 picks up all of Gold Feeder 11. Fault analyses were completed to evaluate the impact of Project Deming on Deming East Feeder 11's ability to detect and interrupt faults while simultaneously serving both feeders.

The Project was modeled in SynerGEE to produce the 2,250 amps of fault current at 270 V for each 500 KVA inverter as noted on the SGIP application form. The SynerGEE model of the 6,000 KVA Project Deming PV plant provided a total of 27,000 A of fault current at 270V for the fault analyses.

The fault analyses show that with Project Deming connected, Deming East Feeder 11 will be able to adequately detect end of circuit faults on Gold Feeder 11 and that adequate coordination is maintained for reclosers and sectionalizers. The fault analysis shows that the fault

contribution of Project Deming will have no adverse impact on the coordination of the installed tap line fuses with the substation relays.

Project Deming does not cause adverse equipment or protective device impacts for a Gold Substation outage.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects of the PV system during daylight hours on the feeder loading were evaluated.

Project Deming output exceeds the 2009 maximum and minimum load on Gold Feeder 11 during daylight hours. No Gold Feeder 11 equipment overloads were identified.

Project Deming output exceeds the 2009 maximum and minimum load on Deming East Feeder 11 during daylight hours. No Deming East Feeder 11 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

The following cost estimates for metering have been developed:

Primary Metering	$ 16,600

The following cost estimates for communication have been developed:

ONE-TIME Equipment COST	$ 35,000
One-Time Labor Cost	$ 10,000
MONTHLY Recurring O&M	$ 3,500

The breakdown of the ONE-TIME communication equipment cost:

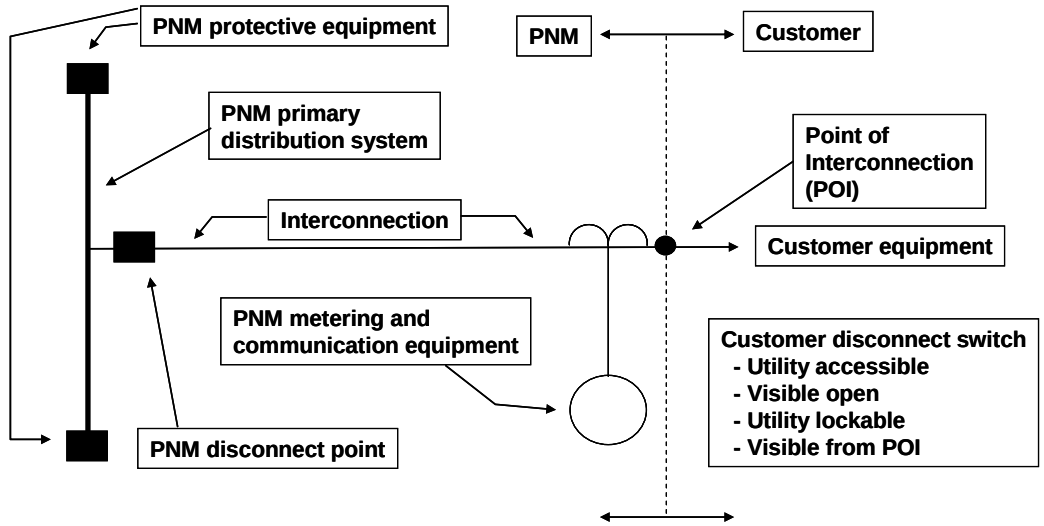
Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$ 20,000
Channel Bank Equipment	$ 10,000

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is a one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



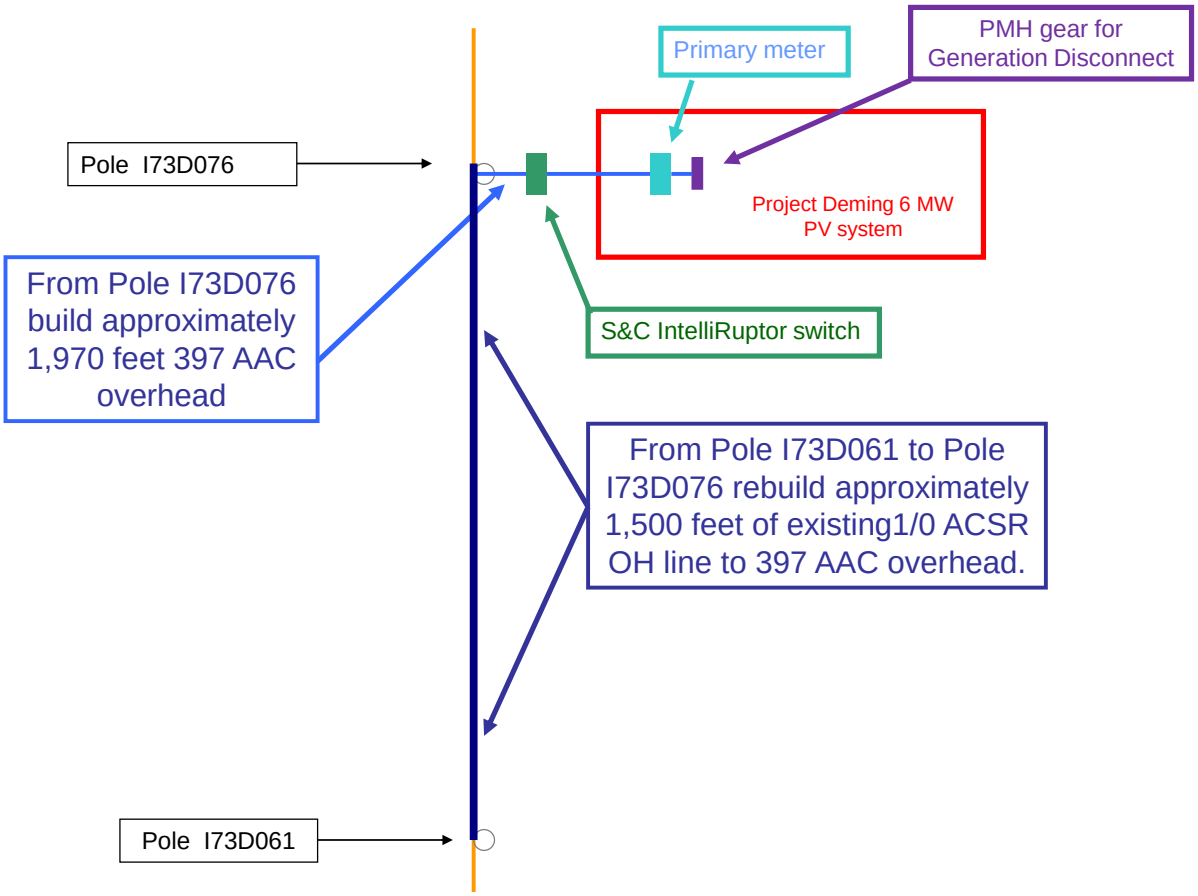
The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

A construction cost estimate was provided for the connection of Project Deming to Gold Feeder 11. See Figure 4 below for the details. The interconnection consists of:

- Extend North from Pole I73D061 approximately 1,500 ft using 397 AAC to Pole I73D076.
- Extend East from Pole I73D076 approximately 1,970 ft using 397 AAC.
- One S&C IntelliRupter switch
- Riser to primary meter, about 20ft, using 750 AL
- PMH gear for Customer Generation Disconnect.

Figure 4 – Line Extension to connect Project Deming to Gold Feeder 11



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 13.

Table 13 ***- Project Deming Interconnection Cost***

	ESTIMATED COSTS 2010$	ESTIMATED CONSTRUCTION TIME
PNM disconnect point*	$ 61,000	~ 26 week lead time ~ 2 days to build
Interconnection**	$ 143,100	~ 1 week lead time ~ 21 days to build
PNM metering	$ 16,600	~ 16 week lead time ~ 4 days to build
Communication	$ 45,000	~16 week lead time ~3 weeks to build
TOTAL	**$ 265,700 Plus monthly O&M of $3,500.**	**6-7 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device.
** Reconductor and extend the distribution primary to the point of interconnection.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

The proposed location for project Deming is located on a parcel of land that has two primary distribution lines running along the western and southern boundaries of the parcel.

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This may involve acquiring easements from multiple land owners. Obtaining these easements should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA).

16.0 CONCLUSIONS

Project Deming does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Gold Feeder 11. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. The one switched capacitor bank on the Gold Feeder 11 is not affected by Project Deming. The automatic control of voltage by the substation LTC may cause the LTC to operate, but this is not anticipated to be an adverse effect. The Project output will cause a flow of electricity from the distribution system through the substation transformer, the difference is minimal, and therefore no transmission voltage issues are anticipated. Analysis showed that the Project output did not cause conductor ratings to be exceeded. Finally, analysis shows that Project Deming output variation will not cause voltage flicker issues for other customers on the distribution system.

Based on this evaluation of the distribution primary system, there are no adverse impacts associated with a 6,000 KVA AC source connected to Gold Substation connected to Gold Feeder 11. System upgrades are not required to ensure that electric service to all customers on Gold Substation is maintained within established PNM voltage, equipment and fault protection criteria.

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[i] *Electric Utility Engineering Reference Book, vol. 3: Distribution Systems*. Trafford, PA: Westinghouse Electric Corporation, 1965.

PNM Generation Planning and Development

Project PNM Las Vegas
6 MW PV Generation Project

Small Generator Interconnection System Impact Study

(OASIS # SGI-PNM-2010-11)

February 2011

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for Public Service Company of New Mexico Generation Planning and Development department by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts department.

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EXECUTIVE SUMMARY

PNM Generation Planning and Development submitted a 'Small Generator Interconnection Request' for the installation of an inverter based, grid-connected photovoltaic system, nominally rated at 6MW AC, connected to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as PNM Project Las Vegas and would be connected to Gallinas Feeder 12. An application was submitted based on the 'Open Access Transmission Tariff of Public Service Company of New Mexico', 'Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW'.

The estimated cost of connecting PNM Project Las Vegas to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM Disconnect Point (IntelliRupter)	$ 48,780	~ 16 weeks lead time ~ 2 days construction
Interconnection (Line Construction)	$ 28,130	~ 16 weeks lead time ~ 5 days construction
PNM Primary Metering	$ 16,710	~ 3 weeks lead time ~ 2 days construction
Communication	$ 45,000	~ 16 weeks lead time ~ 3 days construction
Communication monthly O&M*	$ 3,500	~ 16 weeks lead time ~ 3 weeks construction
TOTAL*	**$ 138,620**	

*Communication monthly O&M cost not included in total.

The application notes the use of twelve of the SMA Solar Technology AG Sunny Central 500 CP inverter, which is not certified UL 1741 compliant. The SMA Sunny Central 500 CP inverter will have a 1000V DC rating and is designed to meet UL 1741 compliance standards. Since UL certification is mostly limited to 600V DC inverters, the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer technical data notes, the inverter is capable of maintaining a unity power factor but also has the capability to control the reactive power to support voltage control. Distribution Planning recommends the use of a UL 1741 listed

inverter to insure, among other concerns, that the unit will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other various requirements as called out in the SGIP application, Attachment 3. A complete field checkout of non-compliant equipment at the proposed facility is recommended before the facility can be considered certified for interconnected operation.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project PNM Las Vegas does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Gallinas Feeder 12 and the analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud will not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. Switched capacitor banks with Autodaptive Capacitor Control may potentially be de-energized but this does not adversely impact voltages. Switching capacitors on during the loss of Gallinas Substation with Project PNM Las Vegas operating would cause unacceptably high voltages. However, this is highly unlikely and would only occur, for a controller malfunction.
6. The Project contribution to fault current minimally impacts the protection coordination on Arriba Feeder 14 for a loss of Gallinas Substation.
7. The Project output will cause a flow of electricity from the distribution system through the substation transformer but since this is less than PNM's threshold of 5 MW over the transformer minimum load, there is no adverse impact on the transmission system anticipated.

Distribution Planning has evaluated the distribution primary system impacts associated with Project PNM Las Vegas and has determined that there is only a small adverse impact associated with a 6,000 KW AC source connected to Gallinas Feeder 12. The Project contribution to fault current minimally impacts the protection coordination on Arriba Feeder 14 for a loss of Gallinas Substation.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Gallinas Feeder 12 is maintained within established PNM voltage, and equipment criteria. However, the tap on the Arriba 14 phase relays will need to be lowered to eliminate exposure to delayed fault clearing times created by the interconnection of Project Las Vegas. This action will ensure electric service is maintained within established PNM fault protection criteria.

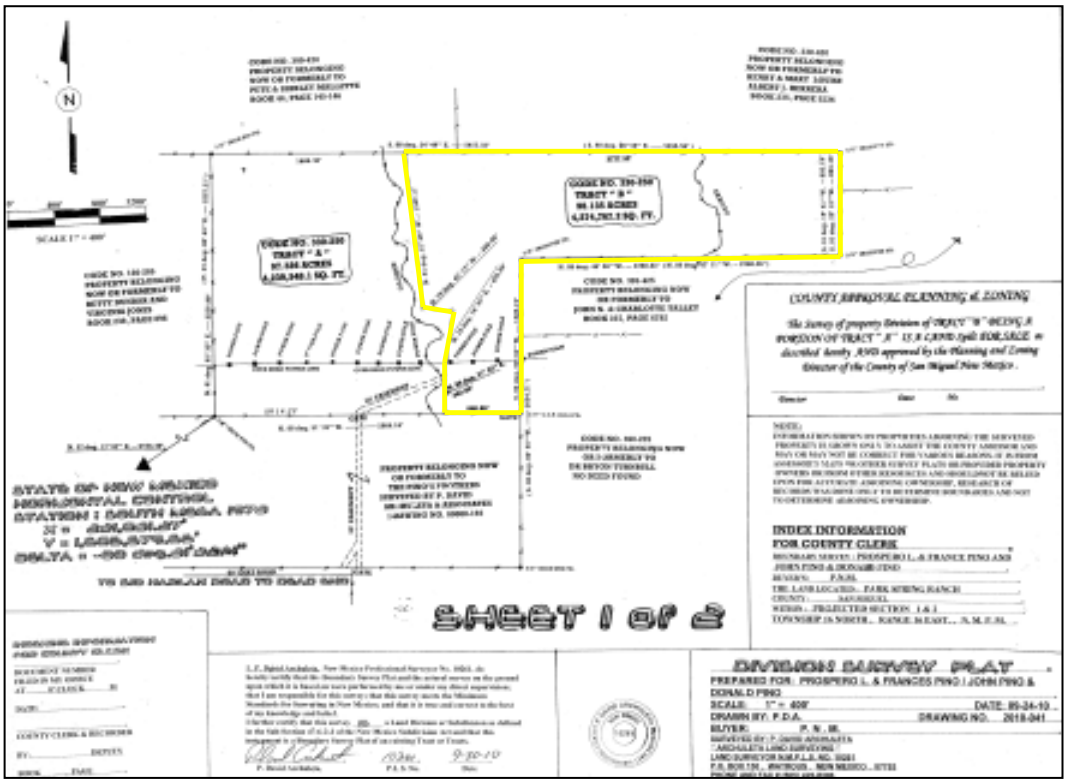
1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source, identified as PNM Project Las Vegas, connected to the distribution primary system. The PV generation source will be connected to the distribution primary using inverters that convert the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

PNM Project Las Vegas proposes to connect a nominal 6MW AC PV facility to one Gallinas Substation Feeder in Las Vegas, NM. The Project will be located in Tract B of the property as shown in Figure 1. The circuit distance from Gallinas Substation to the PNM Project Las Vegas point of interconnection (POI) is about 10,900 ft.

Figure 1 – PNM Project Las Vegas Location



3.0 SYSTEM CONFIGURATION

PNM Project Las Vegas is a large PV source that is proposed to be served by one distribution feeder, Gallinas Feeder 12. Gallinas Substation presently has two distribution feeders serving load. Study analysis is based on connecting the Project to Gallinas Feeder 12. Table 1 shows the rating of Gallinas Substation as determined by the EPRI Ptload program.

Table 1 - Substation transformer nameplate versus Ptload rating

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Gallinas	22.4	22.61	24.95	115-12.47

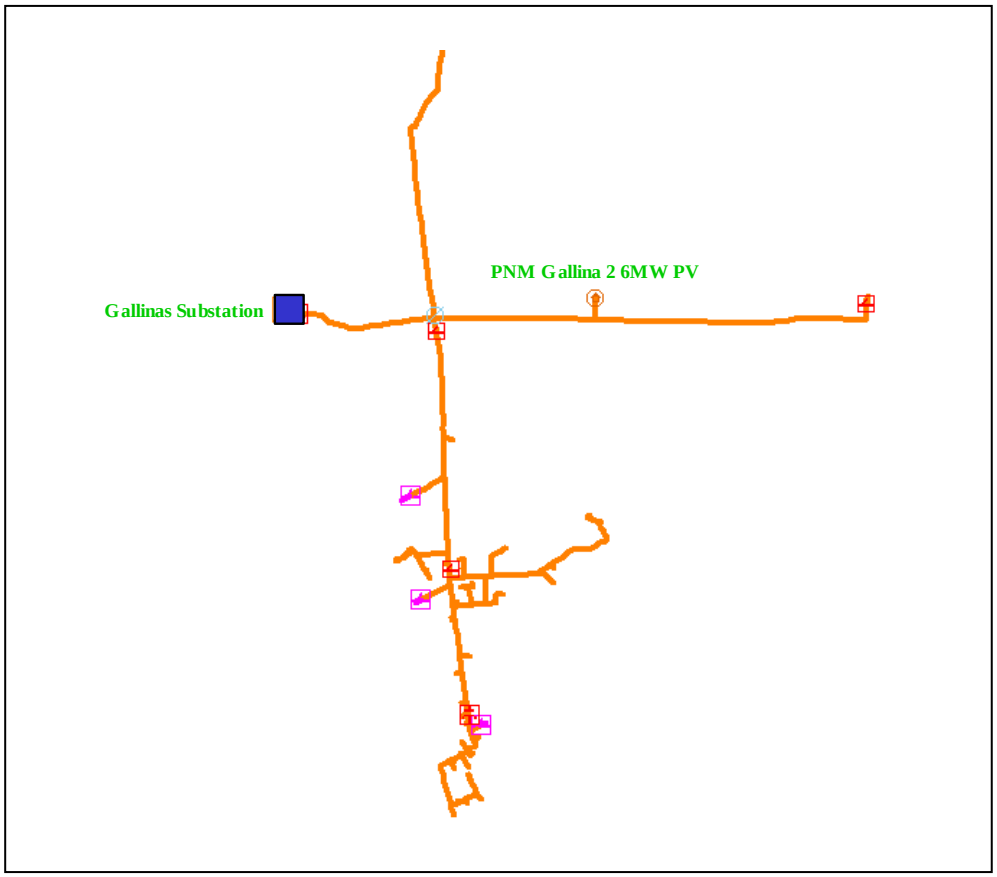
In 2009, PNM's system peak occurred in July. Each year PNM takes a snapshot of its feeder and substation loads in the month of the system peak for planning purposes. Table 2 shows the non-coincident 2009 July peak summer loads for Gallinas Substation and feeders.

Table 2 - July 2009 Non-coincident Peak Loads

Feeder	July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Gallinas				
Gallinas 11	5,999	-1,112	6,101	-98.3
Gallinas 12	5,330	-500	5,353	-99.5
Gallinas Sub	13,007	64	13,007	100.0

Figure 2 is a picture of the distribution feeder used in the Advantica SynerGEE modeling program.

Figure 2 – SynerGEE model of Gallinas Feeder 12



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer are evaluated for two conditions during daylight hours – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit. Typically, PNM defines daylight hours as 7AM-7PM from April through September. Daylight hours for October through March are loosely defined as 8AM to 4PM. However, date and time of the maximum or minimum load is validated to ensure that it indeed occurred during daylight hours when the PV system could still be producing.

The daylight hours maximum and minimum loading on the Gallinas Substation and on Gallinas Feeder 12 are shown in Tables 3 and 4:

Table 3 – Gallinas Substation max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
March 27, 2009	10 AM	9,333	-1,983	9,542	-97.82	450	447	415
August 9, 2009	7 AM	4,598	-2,536	5,251	-87.56	247	243	241

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Table 4 – Gallinas Feeder 12 max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 14, 2009	3 PM	5,130	609	5,166	99.30	226	250	232
May 31, 2009	7 AM	2,433	-889	2,591	-93.93	117	126	113

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

PNM Project Las Vegas has a rated output of 6,000 KW. There are two feeders, Gallinas Feeders 11 and 12, on Gallinas Substation presently serving load. The minimum load on the Gallinas Substation transformer, as shown in Table 3, is less than the rated output of PNM Project Las Vegas. This may result in electricity flowing from the distribution system through the substation transformer to the transmission system during non-peak load conditions. Of concern are the substation bus voltage and regulation as well as impact on the transmission system.

4.1 Voltage impacts on the transmission system

The minimum load on Gallinas Substation during daylight hours is 4,598 kW. The minimum load on the Gallinas Substation transformer is less than the rated output of the project with the difference between the maximum PNM Project Las Vegas generation and the Gallinas transformer load being 749 kW. Since this is less than PNM's threshold of 5 MW over the transformer minimum load, no transmission related issues associated with PNM Project Las Vegas are anticipated.

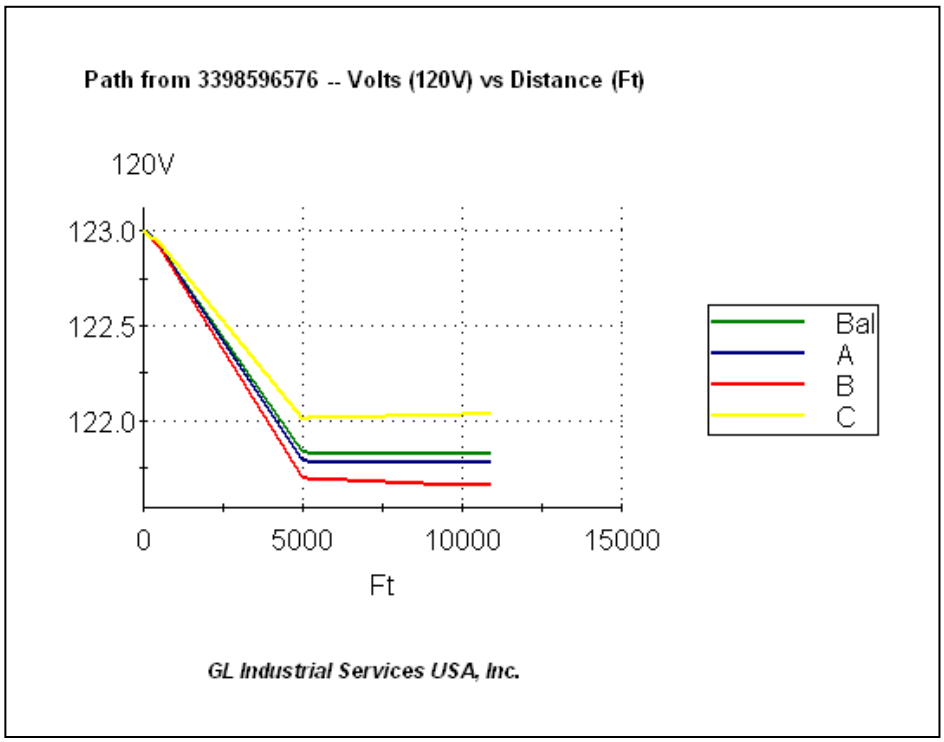
4.2 PV system impacts associated with power factor setting

Scenario's reviewed by this study define an inverter based distributed generation facility operating with a power factor other then unity to be a facility that is absorbing or importing reactive power at the POI. Inverter control systems can be adjusted to allow the PV system to absorb reactive power (Vars) from the distribution system. Recommendations to absorb reactive power at the POI, to mitigate the Project voltage rise impact on the electric distribution system, may be included in the evaluated operating conditions to review the ability of the facility to maintain ANSI C84.1 criteria limits.

4.3 Voltage impacts for maximum daylight hours load for normal configuration

The Gallinas Feeder 12 voltage for the feeder daylight hours maximum load for 2009 with and without Project PNM Las Vegas, per the Synergee model, are shown in Graphs 1 and 2. There were no larger customer loads modeled on the feeder.

Graph 1 – Gallinas Feeder 12 voltage drop from Gallinas Substation to the PNM Las Vegas POI for daylight hours maximum load on July 14, 2009. Project PNM Las Vegas is OFF.

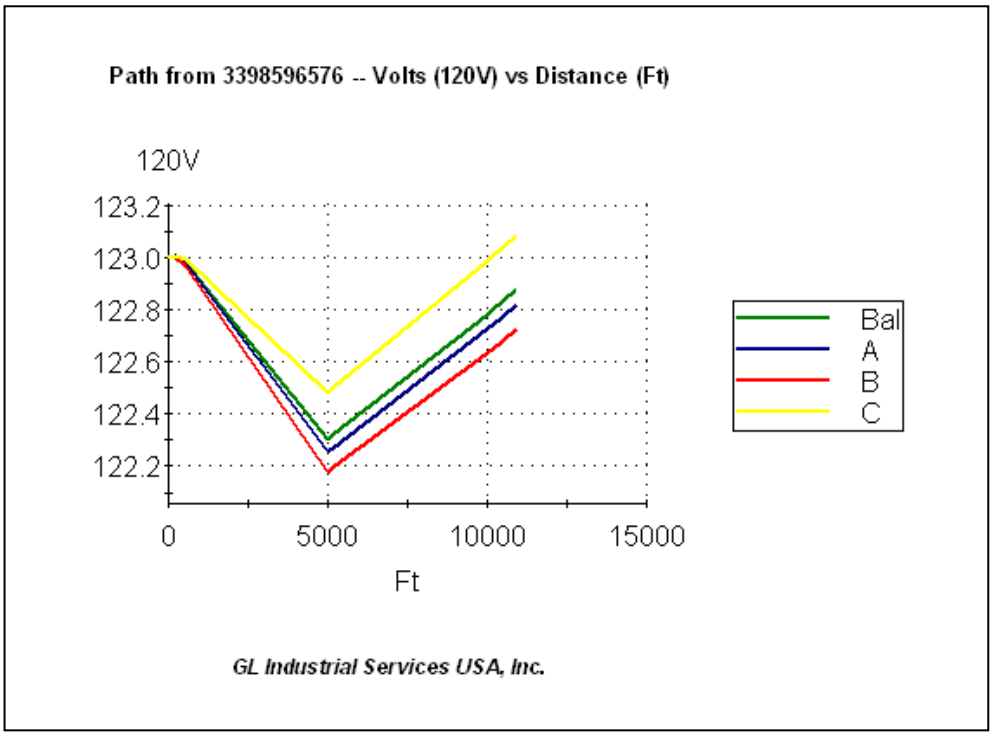


The model voltages at the point of interconnection are:

Phase A – 121.8 volts Phase B – 121.7 volts Phase C – 122.0 volts Balanced – 121.8 volts

The voltages on Gallinas Feeder 12 prior to the installation of PNM Project Las Vegas are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 – Gallinas Feeder 12 voltage drop from Gallinas Substation to the PNM Las Vegas POI for daylight hours maximum load on July 14, 2009. Project PNM Las Vegas is ON, 100% power factor.



The model voltages at the point of interconnection are:

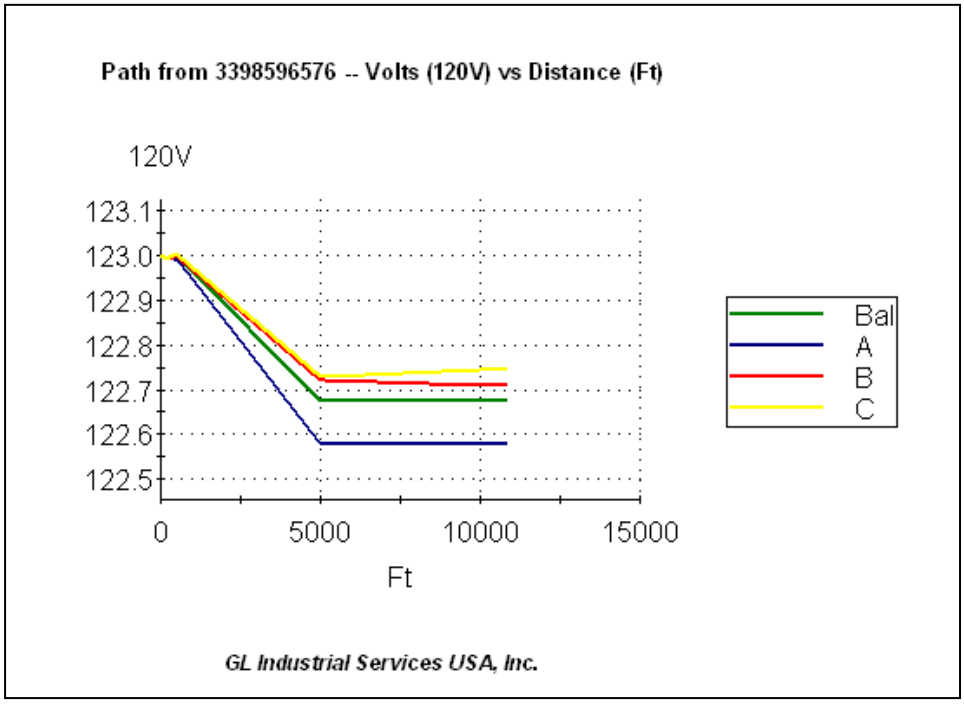
Phase A – 122.8 volts Phase B – 122.7 volts Phase C – 123.1 volts Balanced – 122.9 volts

The voltages on Gallinas Feeder 12 after the installation of Project PNM Las Vegas operating at 100% power factor are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4 Voltage impacts for minimum daylight hours load for normal configuration

The Gallinas Feeder 12 voltage for the feeder daylight hours minimum load for 2009 with and without Project PNM Las Vegas, per the Synergee model, are shown in Graphs 3 and 4. There were no large customer loads modeled on the feeder.

Graph 3 – Gallinas Feeder 12 voltage drop from Gallinas Substation to the Project PNM Las Vegas POI for daylight hours minimum load on May 31, 2009. Project PNM Las Vegas is OFF.

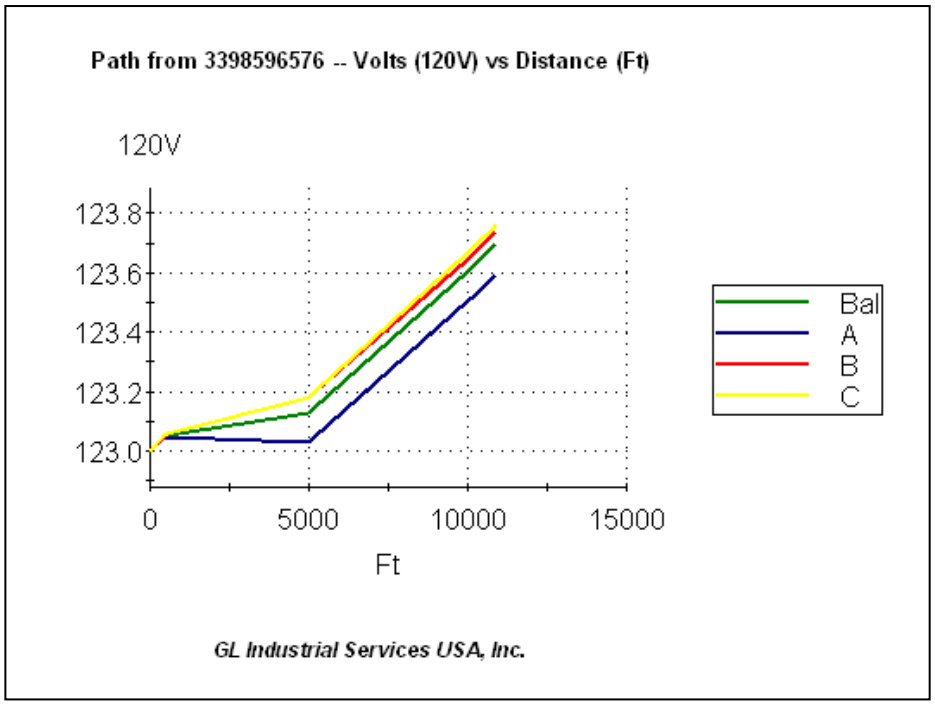


The model voltages at the point of interconnection are:

Phase A – 122.6 volts Phase B – 122.7 volts Phase C – 122.7 volts Balanced – 122.7 volts

The voltages on Gallinas Feeder 12 prior to the installation of Project PNM Las Vegas are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 – Gallinas Feeder 12 voltage drop from Gallinas Substation to the Project PNM Las Vegas POI for daylight hours minimum load on May 31, 2009. Project PNM Las Vegas is ON, 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.6 volts Phase B – 123.7 volts Phase C – 123.8 volts Balanced – 123.7 volts.

The voltages on Gallinas Feeder 12 after the installation of Project PNM Las Vegas operating at 100% power factor are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion for normal configuration, Project PNM Las Vegas output does cause the voltage on Gallinas Feeder 12 to increase if allowed to operate at 100% power factor, but the voltage stays within the PNM criteria of ANSI C84.1.

4.5 Voltage impacts for maximum daylight hours load for contingency configurations

Presently, there are two possible scenarios for contingency configuration that Project PNM Las Vegas can contribute to: the loss of Gallinas Substation, and the loss of Arriba Feeder 11.

4.5.1 Contingency configuration – Loss of Gallinas Substation, maximum load

For the loss of the Gallinas Substation, Gallinas Feeders 11, and 12 are transferred to Arriba Substation through Arriba Feeder 14. The daylight hours maximum and minimum loading on the Arriba Substation, and Gallinas Feeder 11 and Arriba Feeder 11, are shown in Tables 5 and 6. Arriba Feeder 14 is normally an unloaded feeder so there are no maximum and minimum loads for this feeder. Although Arriba 11 and Gallinas 11 had higher peaks in the winter months, the March 27, 2009 peaks were used to ensure a daylight maximum when a PV system would be operating. The Synergee contingency model for the loss of Gallinas Substation, with and without Project PNM Las Vegas, was developed using the non-coincident daytime minimum and maximum feeder loads for the circuits involved. Voltages for Arriba Feeder 14 daylight hours maximum load for 2009 with and without Project PNM Las Vegas for the loss of Gallinas Substation, per the Synergee model, are shown in Graphs 5 and 6. Large customer loads on the feeders, such as the United World College, were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from Arriba Substation to the Project PNM Las Vegas point of interconnection (POI) is about 10,209 ft. or 1.93 miles.

Figure 3 is a picture of the contingent feeder configuration used in the SynerGEE modeling program with Arriba Feeder 14 providing backup support to the area for a loss of Gallinas Substation.

Figure 3 – SynerGEE model of Arriba Feeder 14 for a Loss of Gallinas Substation

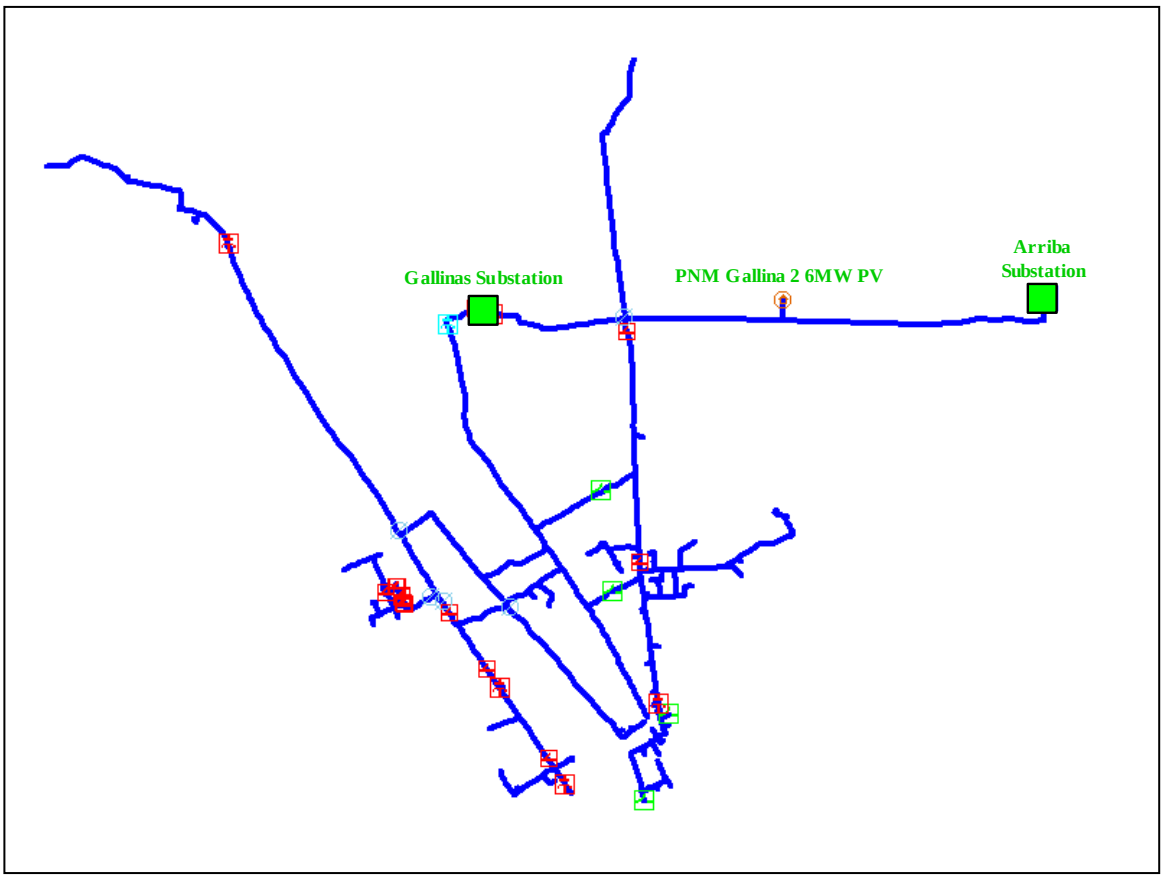


Table 5 – Arriba Substation max/min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
March 27, 2009	11 AM	4,259	-617	4,303	-98.97	180	205	213
June 21, 2009	7 AM	2,110	320	2134	98.87	92	97	100

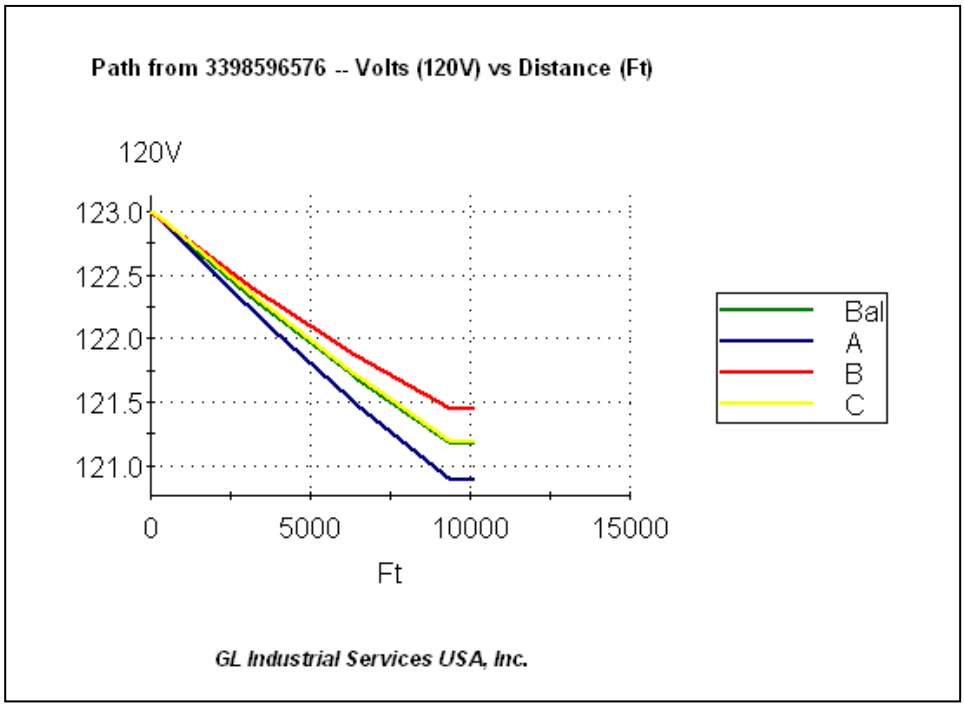
NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Table 6 – Gallinas Feeder 11and Arriba Feeder 11 Max/Min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Gallinas 11								
March 27, 2009	9 AM	4,957	-1212	5103	-97.14	256	219	223
September 6, 2009	7 AM	2,075	-1,875	2,796	-74.19	134	125	122
Arriba 11								
March 27, 2009	11 AM	4,259	-617	4,303	-98.97	180	205	213
June 21, 2009	7 AM	2,110	320	2134	98.87	92	97	100
Arriba 14								
NA	NA	NA	NA	NA	NA	NA	NA	NA
NA	NA	NA	NA	NA	NA	NA	NA	NA

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Graph 5 - Arriba Feeder 14 voltage drop from Arriba Substation to the Project PNM Las Vegas POI for daylight hours maximum loads. Project PNM Las Vegas is OFF.

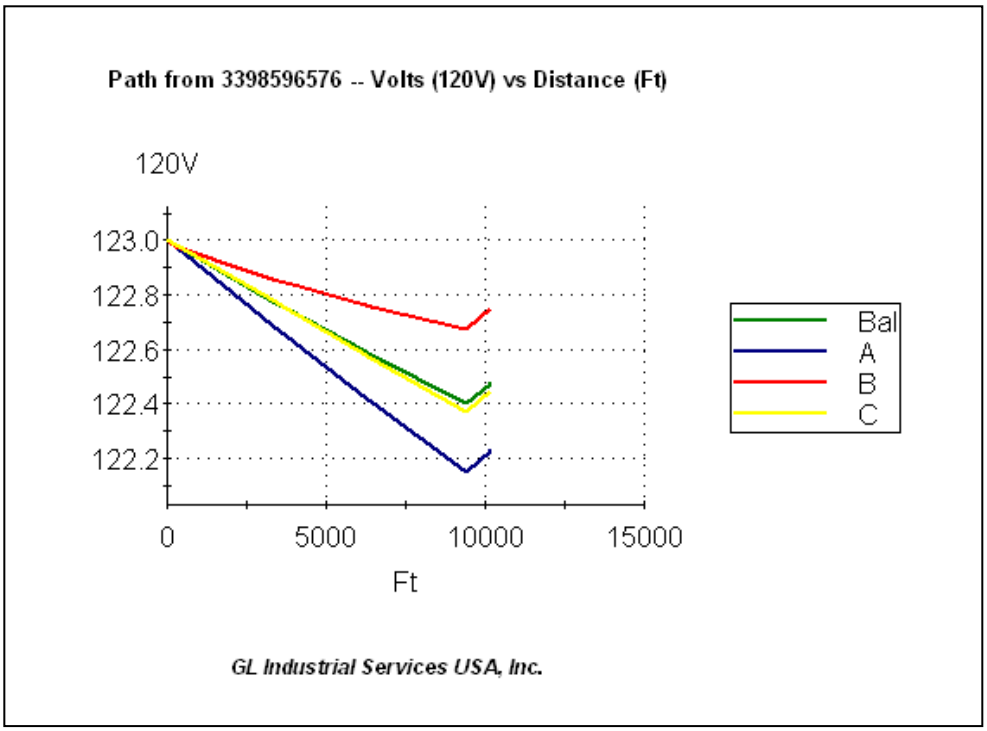


The model voltages at the point of interconnection are:

Phase A – 120.9 volts Phase B – 121.4 volts Phase C – 121.2 volts Balanced – 121.2 volts.

The voltages on Arriba Feeder 14 for the loss of Gallinas Substation prior to the installation of Project PNM Las Vegas are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Arriba 14 overall are 117.6V and 124.2V respectively, which are also within PNM voltage criteria.

Graph 6 - Arriba Feeder 14 voltage drop from Arriba Substation to the Project PNM Las Vegas POI for daylight hours maximum loads. Project PNM Las Vegas is ON, at 100% power factor.



The model voltages at the point of interconnection are:

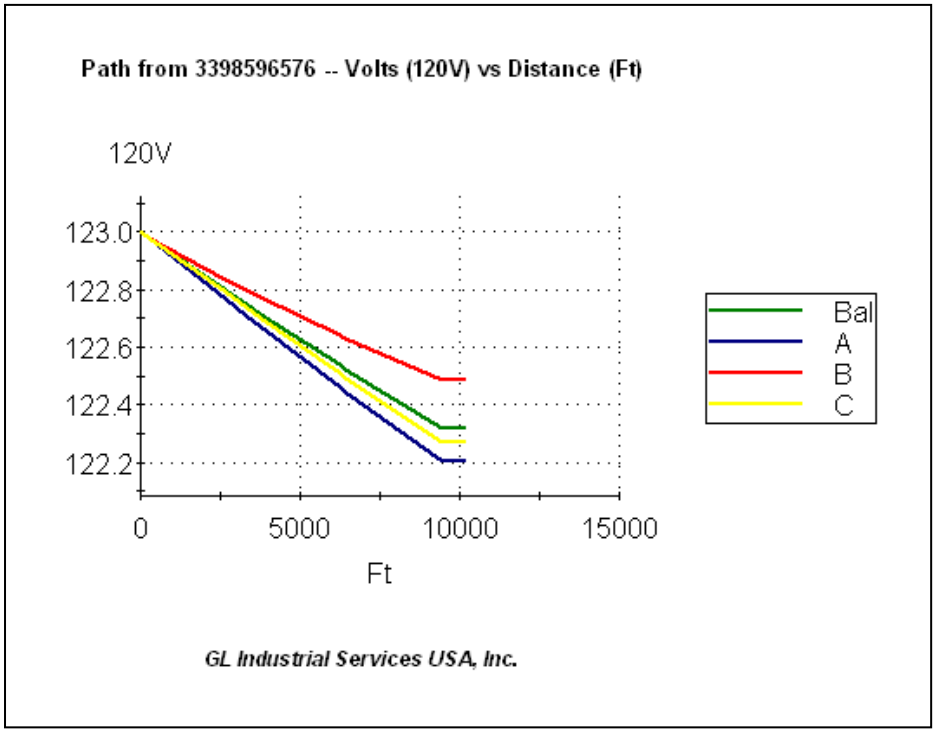
Phase A – 122.2 volts Phase B – 122.8 volts Phase C – 122.4 volts Balanced – 122.5 volts.

The voltages on Arriba Feeder 14 for the loss of Gallinas Substation with Project PNM Las Vegas operating are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Arriba 14 overall are 118.9V and 125.5V respectively, which are also within PNM voltage criteria.

4.5.2 Contingency configuration – Loss of Gallinas Substation, minimum load

For the loss of Gallinas Substation during minimum load conditions, the backup feeder configuration is the same as for maximum load conditions. Arriba Feeder 14 is the backup feeder to the area. However, for the minimum load scenario, switched capacitor banks C108L, C109L, and C113L were modeled off as determined to be the status for the actual 2009 minimum load condition. The fixed capacitor banks, C104L, C105L and C106L, were modeled in service. Voltages for Arriba Feeder 14 daylight hours minimum load for 2009 with and without Project PNM Las Vegas for the loss of Gallinas Substation, per the Synergee model, are shown in Graphs 7 and 8.

Graph 7 - Arriba Feeder 14 voltage drop from Arriba Substation to the Project PNM Las Vegas POI for daylight hours minimum loads. Project PNM Las Vegas is OFF.

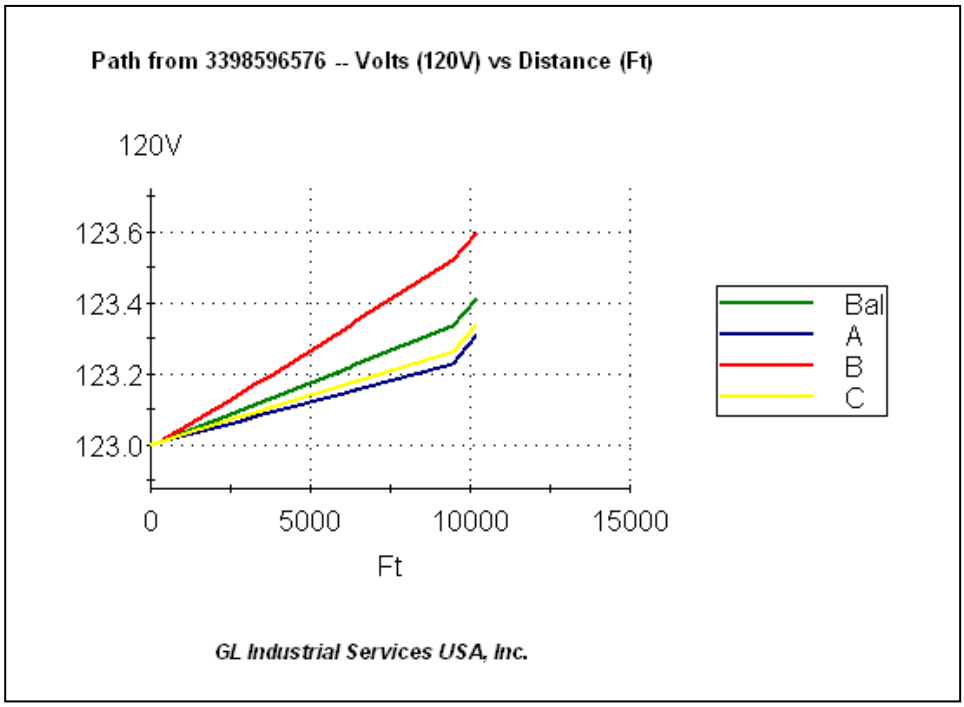


The model voltages at the point of interconnection are:

Phase A – 122.2 volts Phase B – 122.5 volts Phase C – 122.3 volts Balanced – 122.3 volts.

The voltages on Arriba Feeder 14 for the loss of Gallinas Substation prior to the installation of Project PNM Las Vegas are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Arriba 14 overall are 120.7V and 123.7V respectively, which are also within PNM voltage criteria.

Graph 8 - Arriba Feeder 14 voltage drop from Arriba Substation to the Project PNM Las Vegas POI for daylight hours minimum load. Project PNM Las Vegas is ON at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.3 volts Phase B – 123.6 volts Phase C – 123.3 volts Balanced – 123.4 volts.

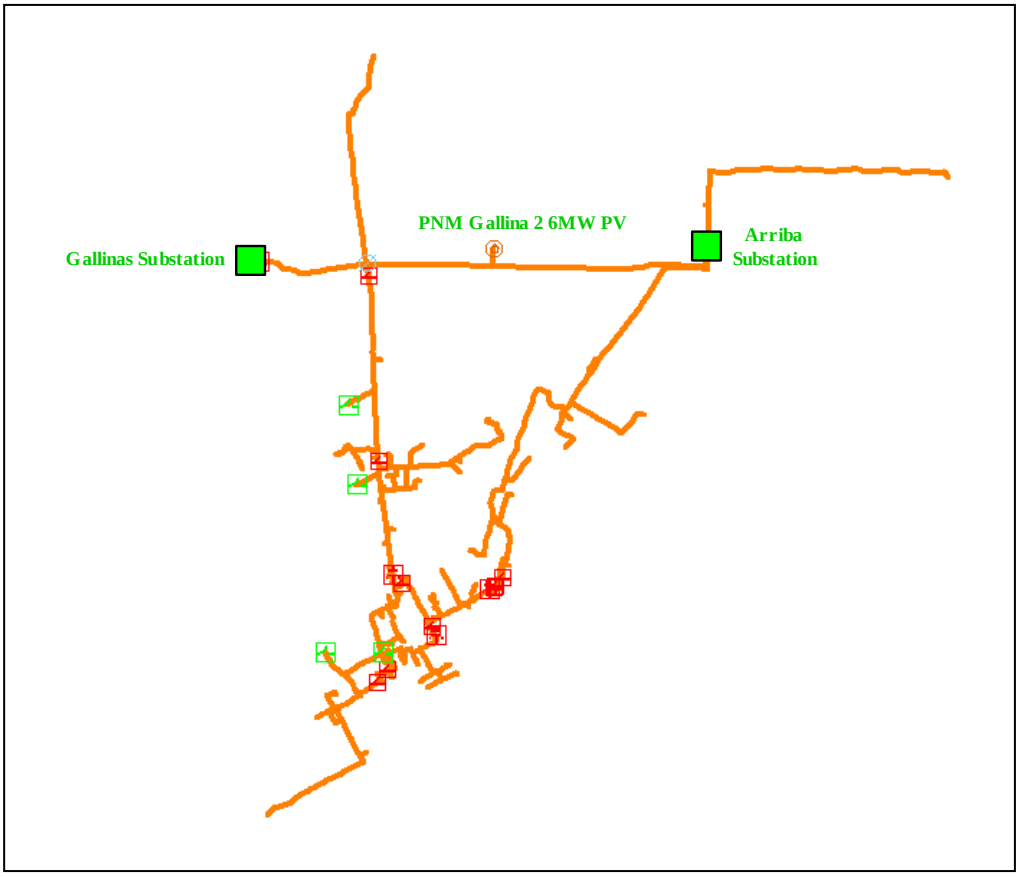
With Project PNM Las Vegas on, calculated voltages on Arriba Feeder 14 for the loss of Gallinas Substation are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Arriba 14 overall are 121.7V and 124.7V respectively, which are also within PNM voltage criteria.

4.5.3 Contingency configuration – Loss of Arriba Feeder 11, maximum load

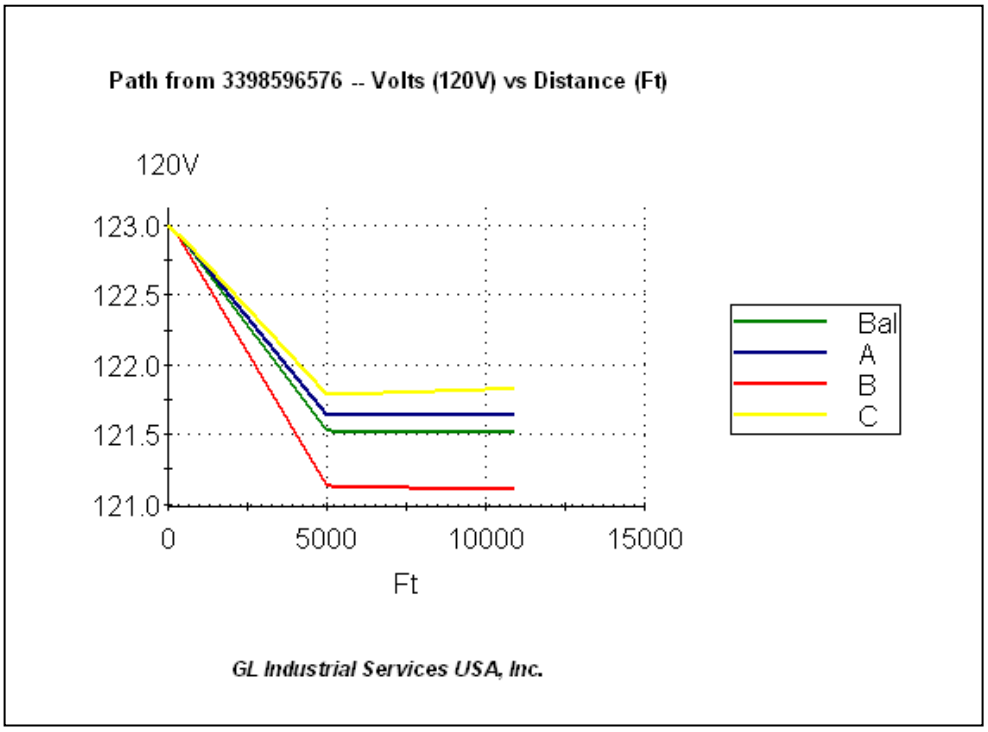
For the loss of the Arriba Feeder 11,100% of Arriba Feeder 11 is transferred to Gallinas Substation through Gallinas Feeder 12. The daylight hours maximum and minimum loading on the Gallinas Substation, Gallinas Feeder 12, and Arriba Feeder 11, are shown in Tables 3, 4, and 6. The Synergee contingency model for the loss of Arriba Feeder 11, with and without Project PNM Las Vegas, was developed using the non-coincident daytime minimum and maximum feeder loads for the circuits involved. Voltages for Gallinas Feeder 12 daylight hours maximum load for 2009 with and without Project PNM Las Vegas for the loss of Arriba Feeder 11, per the Synergee model, are shown in Graphs 9 and 10. Large customer loads on the feeders, such as the United World College, were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from Gallinas Substation to the Project PNM Las Vegas point of interconnection (POI) is about 10,900 ft. or 2.06 miles.

Figure 4 is a picture of the contingent feeder configuration used in the SynerGEE modeling program with Gallinas Feeder 12 providing backup support to the area for a loss of Arriba Feeder 11.

Figure 4 – SynerGEE model of Gallinas Feeder 12 for a Loss of Arriba Feeder 11



Graph 9 - Gallinas Feeder 12 voltage drop from Gallinas Substation to the Project PNM Las Vegas POI for daylight hours maximum loads. Project PNM Las Vegas is OFF.

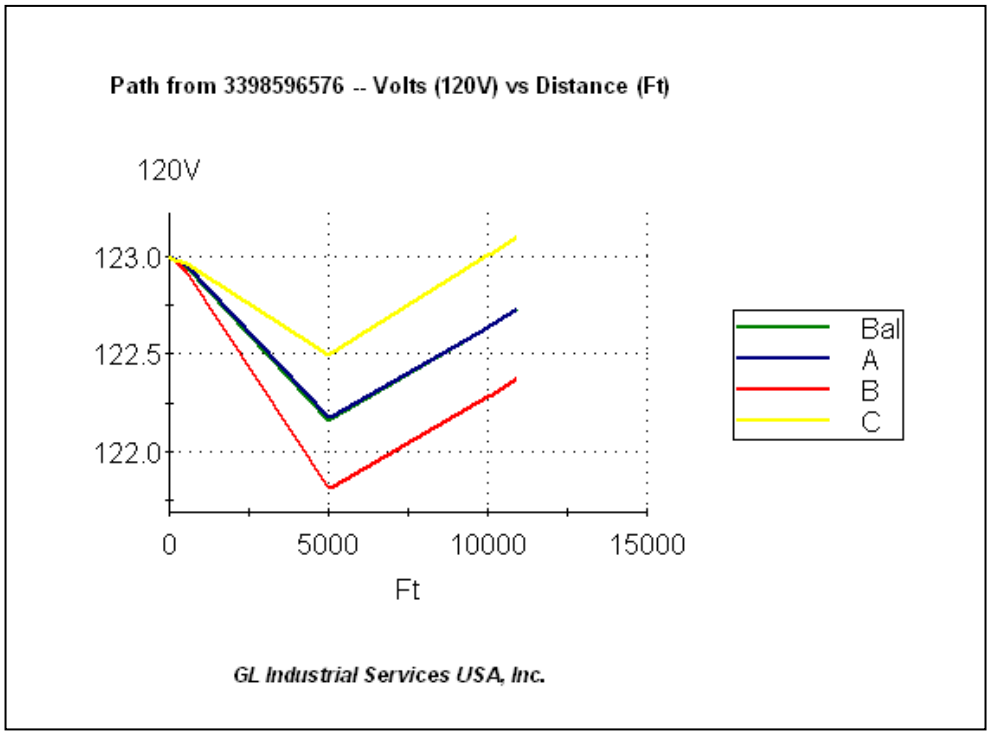


The model voltages at the point of interconnection are:

Phase A – 121.6 volts Phase B – 121.1 volts Phase C – 121.8 volts Balanced – 121.5 volts.

The voltages on Gallinas Feeder 12 for the loss of Arriba Feeder 11 prior to the installation of Project PNM Las Vegas are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Gallinas Feeder 12 overall are 113.3V and 123V respectively. The minimum voltage is not within PNM voltage criteria but can be corrected with a load transfer from Gallinas Feeder 12 to Gallinas Feeder 11 for this contingent condition by opening switch SW15L and closing SW21L.

Graph 10 - Gallinas Feeder 12 voltage drop from Gallinas Substation to the Project PNM Las Vegas POI for daylight hours maximum load. Project PNM Las Vegas is ON at 100% power factor.



The model voltages at the point of interconnection are:

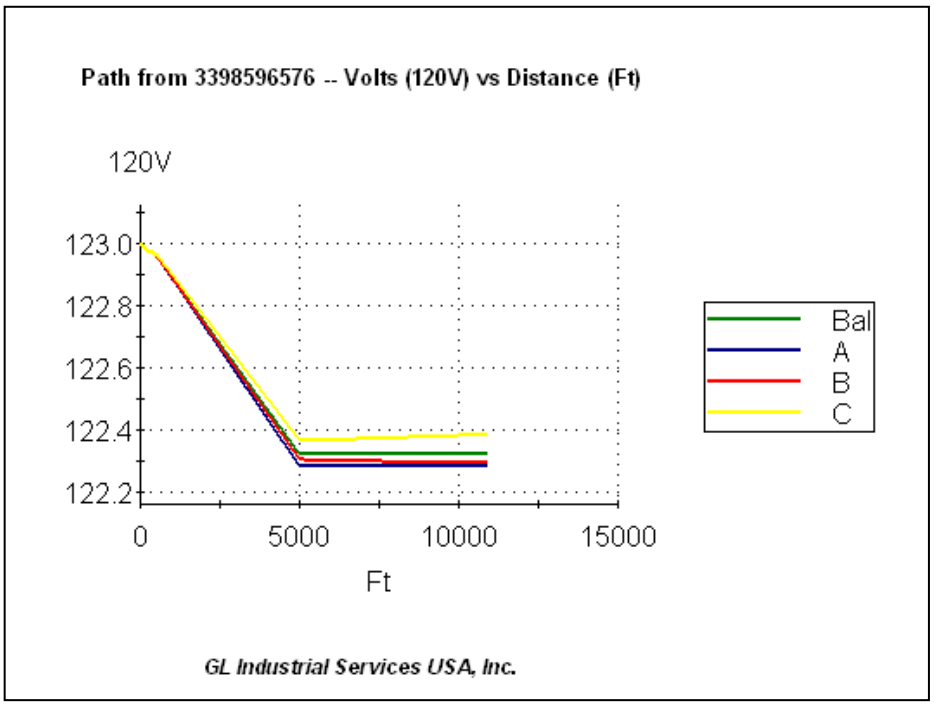
Phase A – 122.7 volts Phase B – 122.4 volts Phase C – 123.1 volts Balanced – 122.7 volts.

With Project PNM Las Vegas on, calculated voltages on Gallinas Feeder 12 for the loss of Arriba Feeder 11 are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Gallinas Feeder 12 overall are 113.9V and 123.0V respectively. The minimum voltage is not within PNM voltage criteria but can be corrected with a load transfer from Gallinas Feeder 12 to Gallinas Feeder 11 for this contingent condition by opening switch SW15L and closing SW21L.

4.5.4 Contingency configuration – Loss of Arriba Feeder 11, minimum load

Voltages for Gallinas Feeder 12 daylight hours minimum load for 2009 with and without Project PNM Las Vegas for the loss of Arriba Feeder 11, per the Synergee model, are shown in Graphs 11 and 12.

Graph 11 - Gallinas Feeder 12 voltage drop from Gallinas Substation to the Project PNM Las Vegas POI for daylight hours minimum loads. Project PNM Las Vegas is OFF.

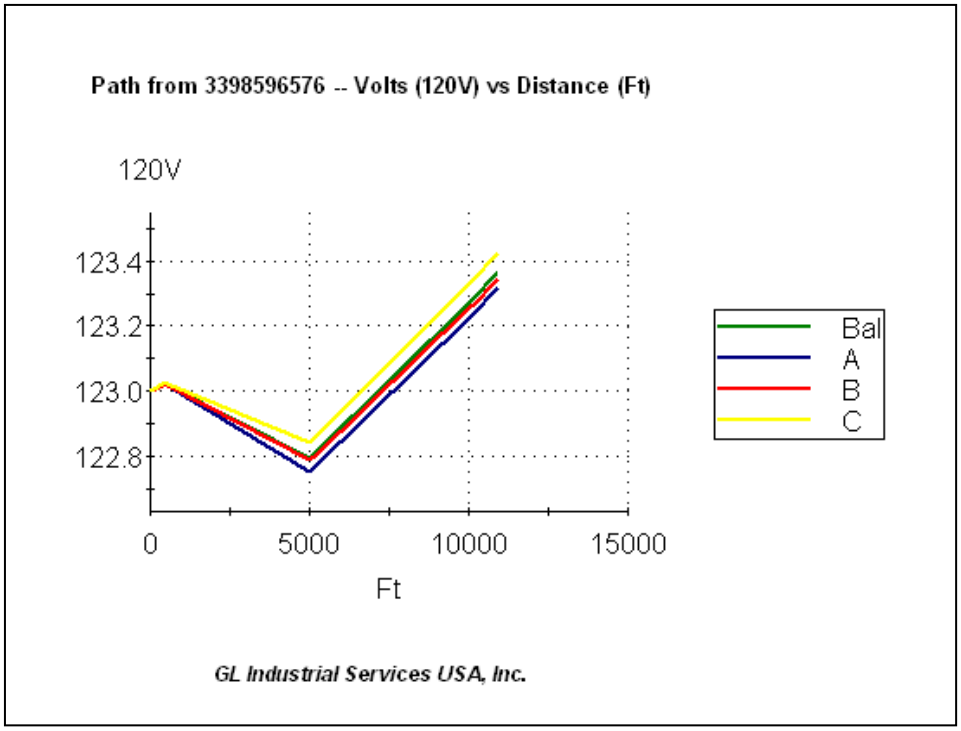


The model voltages at the point of interconnection are:

Phase A – 122.3 volts Phase B – 122.3 volts Phase C – 122.4 volts Balanced – 122.3 volts.

The voltages on Gallinas Feeder 12 for the loss of Arriba Feeder 11 prior to the installation of Project PNM Las Vegas are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Gallinas Feeder 12 overall are 118.3V and 123V respectively and are also within PNM voltage criteria.

Graph 12 - Gallinas Feeder 12 voltage drop from Gallinas Substation to the Project PNM Las Vegas POI for daylight hours minimum load. Project PNM Las Vegas is ON at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.3 volts Phase B – 123.3 volts Phase C – 123.4 volts Balanced – 123.4 volts.

With Project PNM Las Vegas on, calculated voltages on Gallinas Feeder 12 for the loss of Arriba Feeder 11 are within PNM voltage criteria (ANSI C84.1 Range B) at the POI and are acceptable. The minimum and maximum voltages on Gallinas Feeder 12 overall are 118.8V and 123.4V respectively and are within PNM voltage criteria.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Las Vegas is served by Gallinas Feeder 12, and there are no voltage regulators installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

As seen in Tables 7-10, the Synergee modeling shows the substation transformer LTC did not change position for a 6,000 KW source on Gallinas Feeder 12 for high or low load periods. This LTC operation is not considered an adverse impact.

Table 7 – Gallinas Substation with Project PNM Las Vegas OFF for daylight hours maximum load

	GALLINAS SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	123.0	123.0	123.0	123.0
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 7. The voltages at Gallinas Substation prior to the installation of Project PNM Las Vegas are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8 –Gallinas Substation with Project PNM Las Vegas ON at 100% power factor for daylight hours maximum load

	GALLINAS SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	123.0	123.0	123.0	123.0
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 8. The voltages at Gallinas Substation after the installation of Project PNM Las Vegas are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 9 – Gallinas Substation with Project PNM Las Vegas OFF for daylight hours minimum load

	GALLINAS SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.2	124.1	124.1	124.1
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 9. The voltages at Gallinas Substation prior to the installation of Project PNM Las Vegas are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 10 – Gallinas Substation with Project PNM Las Vegas ON, at 100% power factor for daylight hours minimum load

	GALLINAS SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.1	124.1	124.1	124.0
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 10. The voltages at Gallinas Substation after the installation of Project PNM Las Vegas at 100% power factor are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Gallinas Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of the Project PNM Las Vegas output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus borderline of visibility and borderline of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. The voltage regulation equipment installed on a distribution system cannot compensate for a rapid change in load. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not

respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given that the amount of PV system output reduction due to clouds is not known, the assumption is that the output goes to zero when a cloud passes over and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Gallinas Substation bus was fixed at 123 volts with and without Project PNM Las Vegas output for maximum and minimum load periods. Table 10 summarizes the balanced voltage and the calculated voltage flicker at the Project PNM Las Vegas POI. Table 11 is based on the GE flicker graph.

Table 11 - Voltage Flicker at the Project POI due to Project PNM Las Vegas

	Project PNM Las Vegas Voltage at POI	
	Minimum Load	**Maximum Load**
Without Project	122.7	121.8
With Project ON at 100% PF	123.7	122.9
% Voltage Flicker	**0.81**	**0.90**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 12 - Frequency of voltage flicker due to PV output changes

% Voltage Flicker	Fluctuations Based on GE Flicker Curve	
	Border Line of Visibility	Border Line of Irritation
0.81	20/hour	40/minute
0.90	15/hour	25/minute

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

The PV output will vary rather than spike between on and off thus Table 12 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 12. Results are less than the 6% voltage flicker criteria; therefore distribution voltage flicker resulting from changes in Project PNM Las Vegas output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project PNM Las Vegas POI to the substation were reviewed using the Synergee feeder model with and without Project PNM Las Vegas' maximum output of 6,000 KW AC.

There were no conductor loading problems from the POI to the substation on Gallinas Feeder 12 with or without Project PNM Las Vegas for maximum or minimum loading during daylight hours.

8.0 CAPACITORS

Switching capacitor banks in the Las Vegas area are controlled by the Beckwith Electric Company Inc. Autodaptive Capacitor Control. The controls are set to turn the capacitor banks

on when a low voltage of 114V is sensed at the capacitor bank location and turn off if the voltage at the capacitor bank location reaches 124V.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. When the inverter is operating the power factor of the distribution feeder will be affected and will appear to become worse.

Gallinas Feeder 12 has one 1,200 KVAR autodaptive controlled capacitor bank (C108L) and one 600 KVAR fixed capacitor bank (C106L). The July 14, 2009 daylight hours peak load on the feeder was 5,130 KW + j609 KVAR or 5,166 KVA at a 99.30% lagging power factor. Both the switched capacitor and the fixed capacitor were energized during the peak load period. The Synergee model shows the 2009 load is 5,188 KW +j617 KVAR or 5,225 KVA at a 99% lagging power factor with the capacitor banks energized so the model correlates to the measured load. Project PNM Las Vegas operating at 100% power factor would change the apparent feeder loading to –782 KW + j677 KVAR or 1034 KVA at a 76% leading power factor (-76%PF). The negative KW indicates that Gallinas Feeder 12 is exporting power to the PNM transmission system. The voltage at capacitor C108L is 123V, but since the switched capacitor on the circuit is already energized prior to switching Project PNM Las Vegas on, no additional capacitance would be switched on so there are no over voltage issues caused by switched capacitors. Should capacitor C108L switch off, the minimum voltage on the circuit drops to 118.96V, which is acceptable. There are no issues associated with operating Project PNM Las Vegas in conjunction with the autodaptive voltage controlled capacitor bank during maximum load conditions. The power factor does change to a very leading –76% when the PV system is operating, but the Synergee model shows that there are no voltage problems.

This study also examined switching autodaptive controlled capacitor banks under minimum load conditions to see what affect this would have on the system with the inverter operating at 100% power factor. The May 31, 2009 daylight hours minimum load on the feeder was 2,433 KW – j889 KVAR or 2,591 KVA at a – 93.93% leading power factor. Both the switched capacitor (C108L) and the fixed capacitor (C106L) were energized during the minimum load period. The Synergee model shows the 2009 daylight minimum load is 2,466 KW – 903 KVAR or 2,626 KVA at 94% leading power factor with the capacitor banks energized so the model correlates to the measured load. At minimum feeder load, operating Project PNM Las Vegas at 100% power

factor would change the apparent feeder loading to – 3,492 KW – j741 KVAR or – 3570 KVA at a 98% leading power factor (-98%PF). The negative kVAR indicate that Gallinas Feeder 12 is exporting VARs to the PNM transmission system. The voltage at capacitor C108L is 123.1V, but since the single switched capacitor on the circuit is already energized prior to switching Project PNM Las Vegas on, no additional capacitance would be switched on so there are no over voltage issues caused by switched capacitors. Should capacitor C108L switch off, the minimum voltage on the circuit drops to 121.86V, which is acceptable. There are no issues associated with operating Project PNM Las Vegas in conjunction with the autodaptive voltage controlled capacitor bank during minimum load conditions. The power factor does change to 98% lagging, but the Synergee model shows that there are no voltage problems.

For the loss of Gallinas Substation while Arriba 14 is providing backup support to the area, there are three 1,200 KVAR autodaptive controlled capacitor banks (C108L, C109L, C113L) and three 600 KVAR fixed capacitor banks (C104L, C105L, C106L) on Arriba Feeder 14. There are no capacitor banks between Project PNM Las Vegas and Arriba Substation. During the contingency analysis for the loss of Gallinas Substation, the status of each capacitor bank was modeled according to its estimated status in the field at the time of the daytime peak or minimum load. Initially for the feeder daytime maximum load, one 1200 KVAR capacitor bank (C109L) closest to Arriba Substation was off, and the other two 1200 KVAR capacitor banks (C108L and C113L) on the circuit were on. With this capacitor configuration and with Project PNM Las Vegas operating at 100% power factor, the Synergee model shows that load on Arriba Feeder 14 would be 4,258 KW – j50 KVAR or 4,259 KVA at 100% leading power factor (–100% PF). The negative KVAR indicate that Arriba Feeder 14 is exporting VARs to the PNM transmission system. The voltage at capacitor C109L is 122.1V. Since the voltage is greater than 114V, the “turn on” voltage for the switched capacitor, no additional capacitance would be switched on so there are no over voltage issues caused by switched capacitors. Should capacitor C109L switch on, the maximum voltage on the circuit increases to 128.08V, which is outside PNM’s voltage criteria. This scenario is highly unlikely and would only occur for a controller malfunction.

For the daytime feeder minimum load, all three 1200 KVAR capacitors were estimated as being off and were modeled in Synergee as being off. With Project PNM Las Vegas operating at 100% power factor, the Synergee model shows the load on Arriba Feeder 14 as – 1473 KW – j120 KVAR or 1480 KVA at - 67% leading power factor (– 67%). The negative KVAR indicate that

Arriba Feeder 14 is exporting VARs to the PNM transmission system. There are no voltage issues with all of the autodaptive controlled capacitor banks off. The voltage at all three switched capacitor locations is at approximately 123V, which is well above the 114V “turn on” voltage for these banks so none of the autodaptive controlled capacitor banks should switch on. However, turning any of the three switched capacitor banks on while Project PNM Las Vegas is operating will cause unacceptably high voltages. This scenario is highly unlikely and would only occur for a controller malfunction.

9.0 PROTECTION

9.1 Normal Configuration

Gallinas Substation feeder 12 is protected by a 1200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, CA differential relays. The Las Vegas Project PV system will be connected to the system approximately 1.92 miles from the substation. There is one hydraulic recloser approximately 0.92 miles from the PV Project.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at the recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Las Vegas does not require system protection improvements to be made to the Gallinas Substation feeder 12 under normal configuration.

9.2 Normal Feeder as a Backup Feeder

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at the recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Las Vegas does not require system protection improvements to be made to the Gallinas Substation feeder 12 under normal feeder as a backup feeder.

9.3 Contingency Configuration

Arriba Substation feeder 14 is protected by a 1200 amp breaker in metal clad switchgear with three GE, IAC77 phase overcurrent relays and one GE, IAC53 ground overcurrent relay. There is also a GE, NLR reclosing relay. The switchgear bus and feeder is protected by three GE, IAC53 phase overcurrent relays and one GE, IAC53 ground relay. The transformer protection is three GE, STD differential relays. The Las Vegas Project PV system will be connected to the system approximately 1.81 miles from the substation. There is one hydraulic recloser approximately 0.92 miles from the PV Project.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at each recloser, for faults on the system anywhere on the loadside of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder. However, fault current from the substation is reduced because of the contribution of the PV system. Portions of the feeder are exposed to delayed fault clearing.

Project Las Vegas does require system protection improvements to be made to the Arriba Substation feeder 14 under contingency configuration. Distribution Protection recommends lowering the tap on the Arriba 14 phase relays to eliminate exposures created by the interconnection of Project Las Vegas.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on the feeder loading were evaluated for operating Project PNM Las Vegas during daylight hours where daylight hours were defined as 7:00 AM to 7:00 PM from April through September. Daylight hours for October through March are loosely defined as 8:00 AM to 4:00 PM. However, date and time of the maximum or minimum load is validated to ensure that it indeed occurred during daylight hours when the PV system could still be producing.

The output of Project PNM Las Vegas exceeds the 2009 maximum and minimum load on Gallinas Feeder 12 during daylight hours. However, no Gallinas Feeder 12 equipment overloads were identified for the normal feeder configuration.

For the loss of Gallinas Substation with Project PNM Las Vegas operating at full output, the Project PNM Las Vegas output exceeds the 2009 minimum load on the backup feeder, Arriba Feeder 14, during daylight hours. It does not exceed the 2009 maximum load on the Arriba 14 backup feeder. No Arriba Feeder 14 equipment overloads were identified in this contingent configuration while Project PNM Las Vegas is operating for either the minimum or maximum load condition.

For the loss of Arriba Feeder 11 with Project PNM Las Vegas operating at full output, the Project PNM Las Vegas output exceeds the 2009 minimum load on the backup feeder, Gallinas Feeder 12, during daylight hours. No Gallinas Feeder 12 equipment overloads were identified for an Arriba Feeder 11 outage with Project PNM Las Vegas operating at full output during minimum load. For the loss of Arriba Feeder 11, Project PNM Las Vegas operating at full output does not exceed the 2009 maximum load on the backup feeder. There were no Gallinas Feeder 12 equipment overloads identified for an Arriba Feeder 11 outage with Project PNM Las Vegas operating at full output for the 2009 maximum load condition.

11.0 METERING and COMMUNICATION

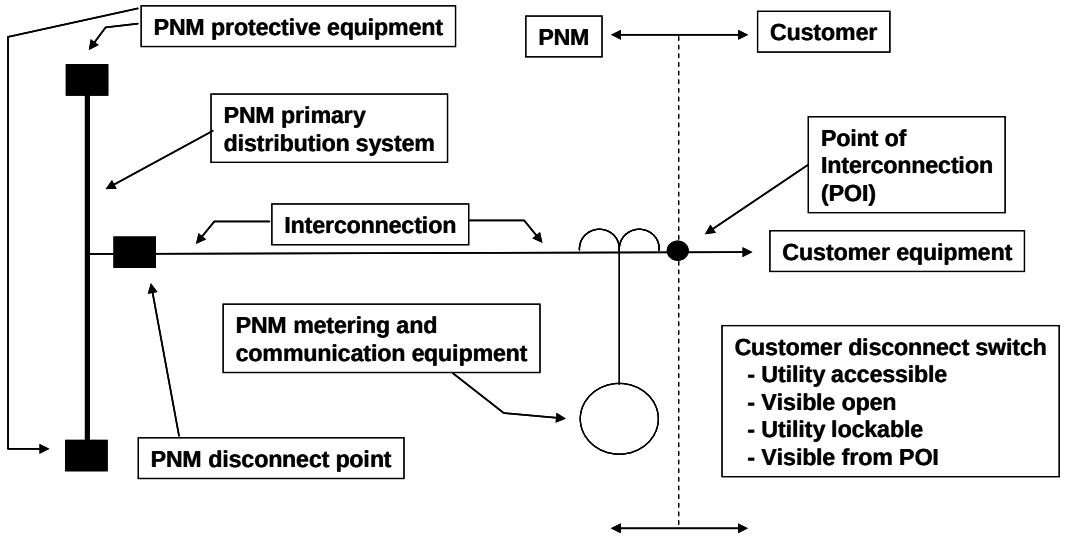
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. The metering equipment will be capable of capturing the PV system's generation profile data in the time intervals specified in the interconnection agreement. Also located at the same point will be communication equipment that will allow PNM to access and download data from the meters into the PNM monitoring system in real time. The meter information will be used to monitor the PV system's output level (KW and KWH) and operational status instantaneously, historically, and for billing purposes.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 5 is a one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 5 – Typical Project Interconnection

Typical connection of a Photovoltaic system to the PNM distribution system



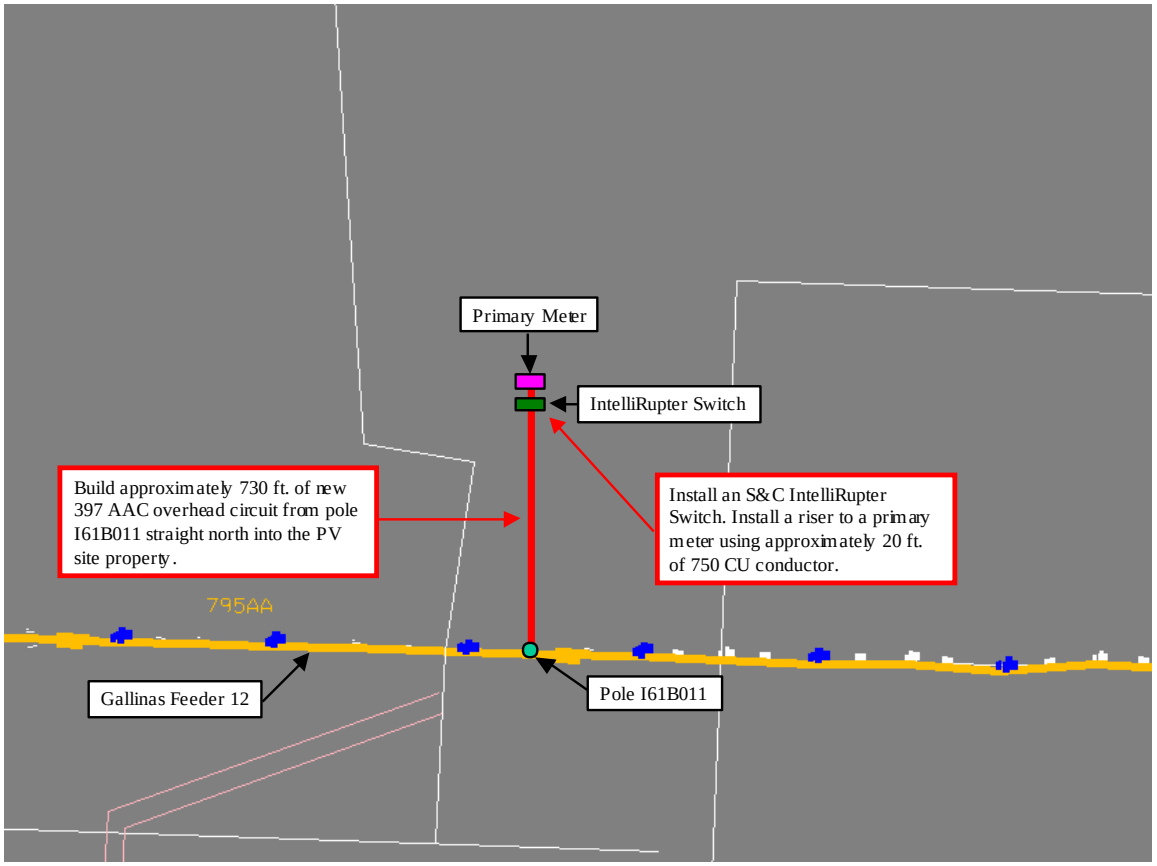
The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project PNM Las Vegas to the PNM distribution system, a line extension is required. No other system upgrades are required. The interconnection consists of:

- Building approximately 730 ft. of new 397 AAC overhead circuit from pole I61B011 straight north into the PV site property. (See Figure 6).
- Install one S&C IntelliRupter switch (See Figure 6).
- Install Primary Metering (See Figure 6).

Figure 6 – Line Extension for Interconnection



The estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 13.

Table 13 - Project PNM Las Vegas Interconnection Cost

	ESTIMATED COSTS 2010$	ESTIMATED CONSTRUCTION TIME
PNM Disconnect Point (IntelliRupter)	$ 48,780	~ 16 weeks lead time ~ 2 days construction
Interconnection (Line Construction)	$ 28,130	~ 16 weeks lead time ~ 5 days construction
PNM Primary Metering	$ 16,710	~ 3 weeks lead time ~ 2 days construction
Communication	$ 45,000	~ 16 weeks lead time ~ 3 days construction
Communication monthly O&M*	$ 3,500	~ 16 weeks lead time ~ 3 weeks construction
TOTAL*	**$ 138,620**	

*Communication monthly O&M cost not included in total.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple landowners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition is not expected to be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA).

16.0 CONCLUSIONS

The location of Project PNM Las Vegas results in an interconnection with Gallinas Feeder 12. Project PNM Las Vegas does not have an adverse impact on the PNM distribution system when operating at 100% power factor. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Autodaptive Capacitor Controlled switched capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will cause a flow of electricity from the distribution system through the substation transformer but since this is less than PNM's threshold of 5 MW over the transformer minimum load, there is no adverse impact on the transmission system anticipated. Analysis also shows that the Project output does not cause conductors ratings to be exceeded. Finally, analysis shows that Project PNM Las Vegas output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project PNM Las Vegas and has determined that there is only a small adverse impact associated with a 6,000 KW AC source connected to Gallinas Feeder 12. The Project contribution to fault current minimally impacts the protection coordination on Arriba Feeder 14 for a loss of Gallinas Substation.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Gallinas Feeder 12 is maintained within established PNM voltage, and equipment criteria. However, the tap on the Arriba 14 phase relays will need to be lowered to eliminate exposure to delayed fault clearing times created by the interconnection of

Project Las Vegas. This action will ensure electric service is maintained within established PNM fault protection criteria.

The application notes the use of twelve of the SMA Solar Technology AG Sunny Central 500 CP inverter, which is not certified UL 1741 compliant. The SMA Sunny Central 500 CP inverter will have a 1000V DC rating and is designed to meet UL 1741 compliance standards. Since UL testing is limited to 600V systems, the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer technical data notes, the inverter is capable of maintaining a unity power factor but also has the capability to control the reactive power to support voltage control. Distribution Planning recommends the use of a UL 1741 listed inverter to insure, among other concerns, that the unit will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other various requirements as called out in the SGIP application, Attachment 3. A complete field checkout of non-compliant equipment at the proposed facility is recommended before the facility can be considered certified for interconnected operation.

Public Service Company of New Mexico
Generation Planning and Development

Project Los Chavez 6,000 KVA PV Generation Project

Small Generator Interconnection Feasibility Study

(SGI-PNM-2010-12)

February 2011

Prepared by:

Public Service Company of New Mexico
Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for Public Service Company of New Mexico Generation Planning and Development Department by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

Public Service Company of New Mexico Generation Planning and Development submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system with a nominal rating of 6,000 KVA AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Los Chavez and would be connected to Los Chavez Feeder 12. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study was performed by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts (Distribution Planning).

The estimated cost of connecting Project Los Chavez to the distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point *	$ 52,000	~16 week lead time ~3 Days to build
Interconnection **	$650,000	~8 week lead time ~12-14 weeks to build
PNM Primary metering	$ 25,000	~3 week lead time ~ 4 days to build
Communications	$ 45,000	~16 week lead time ~3 weeks to build
Protection ***	$ 0	
ROW	$ 31,000	
TOTAL	**$ 803,000**	**7-8 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device
** Extend the distribution primary to the point of interconnection
*** Substation protection scheme modification

The technical data notes for the SMA SC 500CP inverter were used to prepare this report. The data shows that this inverter is presently not a certified UL 1741 compliant inverter. The SMA SC 500CP inverter will have a 1000V DC rating and is designed to meet UL 1741 compliance

standards. The project is requesting a variance to the UL 1741 compliance standard since most UL compliant inverters that have completed UL testing are 600V dc rated devices. Based on the manufacturer technical data notes the inverter is capable of maintaining a unity power factor but also has the capability to control the reactive power to support voltage control. Due to voltage control issues identified in this report, voltage regulation will be required, which precludes the use of presently available UL 1741 compliant inverters. Distribution Planning recommends the use of a UL listed 1741 compliant inverter to insure that, among other concerns, that the unit will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other various requirements as called out in the SGIP application, Attachment 3. A complete field checkout of non-complaint equipment at the proposed facility is recommended before the facility can be considered certified for interconnection operation.

This System Impact Study (Study) evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Los Chavez does not have an adverse impact on the PNM distribution system when operated at a fixed 96% power factor importing VARs for normal or contingency conditions.

The Project location will result in an interconnection with Los Chavez Feeder 12 and the analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds are not anticipated to cause voltage flicker problems.
4. Project output did not cause conductor ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized and could adversely impact voltages, but this is not due to the addition of the Project, these conditions are pre-existing.

6. The Project contribution to fault current does not require the Los Chavez Feeder 12, Los Chavez Feeder Substation, San Clemente Feeder 12 or San Clemente Substation protection scheme be modified.
7. Project output will cause a flow of electricity from the distribution system through the substation transformer, but this is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Los Chavez and has determined that there are no adverse impacts associated with a 6,000 KVA AC source connected to Los Chavez Substation when connected to Los Chavez Feeder 12 when operating at 96% power factor importing VARs.

Distribution Planning has determined that system upgrades are required to ensure that electric service to all customers on Los Chavez Substation is maintained within established PNM voltage, equipment and fault protection criteria.

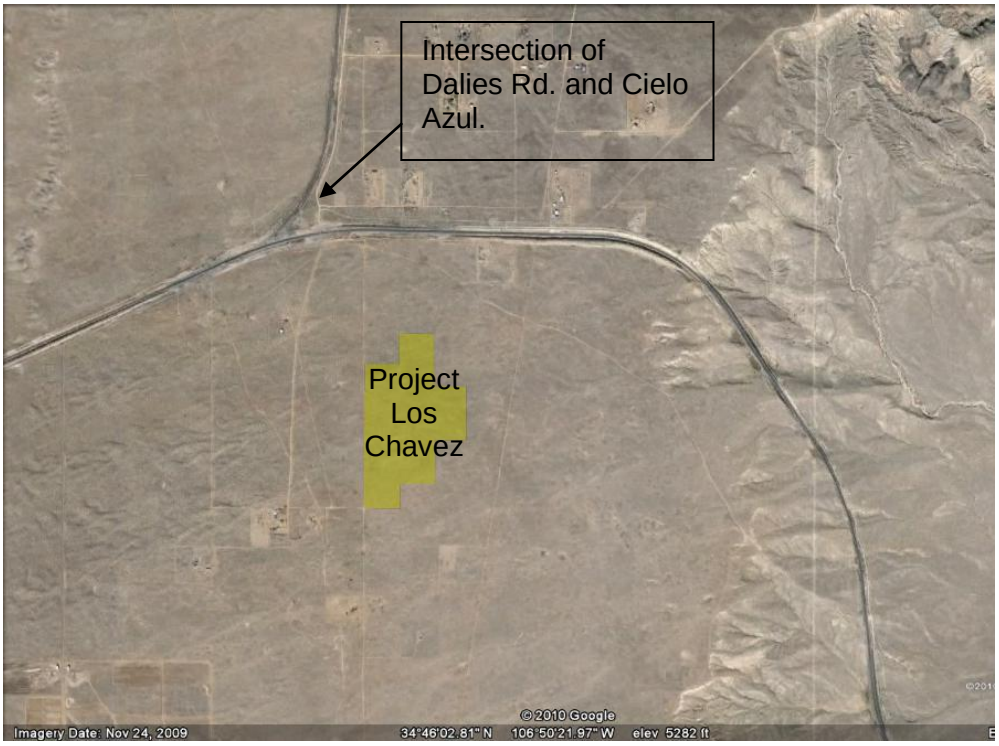
1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Los Chavez. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Los Chavez proposes to connect a 6,000 KVA AC PV facility to Los Chavez Feeder 12 in Dalies Township, NM. The Project Los Chavez is located in Sections 4 and 9 of Township 6 North, Range 1 East in Valencia County, southeast of the intersection of Dalies Rd and Cielo Azul and south of the railroad, as shown in Figure 1. The circuit distance from Los Chavez Substation to the Project Los Chavez point of interconnection (POI) is about 59,281 ft. or 11.23 miles.

Figure 1* – *Project Los Chavez Location



3.0 SYSTEM CONFIGURATION

Project Los Chavez is a large PV source and is proposed to be connected to Los Chavez Feeder 12 served from Los Chavez Substation. Table 1 shows the rating of Los Chavez Substation as determined by the EPRI Ptload program.

Table 1 ***– Substation transformer nameplate versus Ptload rating***

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Los Chavez	14.0	15.40	16.30	46 -12.47

Table 2 shows the 2010 peak summer loads for Los Chavez Substation and feeders, this data is not coincident with PNM's 2010 system wide peak demand timeframe.

Table 2 ***– July 2010 Non-coincident Peak Loads***

Feeder	July 2010 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Los Chavez 11	3,722	1,862	4,162	89.4
Los Chavez 12	4,172	890	4,266	97.8
Los Chavez Substation	7,743	2,643	8,182	94.6

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Los Chavez Feeder 12 are shown in Table 3:

Table 3 *– Los Chavez Feeder 12 max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Aug. 15, 2010	5 PM	4,139	-328	4,152	-99.7	151	181	234
Sept. 23, 2010	9 AM	1,435	-759	1,623	-88.4	66	73	89

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Los Chavez at maximum output exceeds the load on Los Chavez Feeder 12. Therefore, Project Los Chavez will cause a flow of power into Los Chavez Substation. Table 4 shows the maximum and minimum load on the Los Chavez Substation transformer.

Table 4 *– Los Chavez Substation max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
June 9, 2010	6 PM	5,333	-1,131	5,452	-97.8	165	297	312
June 19, 2010	7 AM	2,027	-464	2,079	-97.5	78	117	113

Project Los Chavez at maximum output, exceeds the load on the Los Chavez Substation transformer. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system.

4.1 Voltage impacts on the transmission system

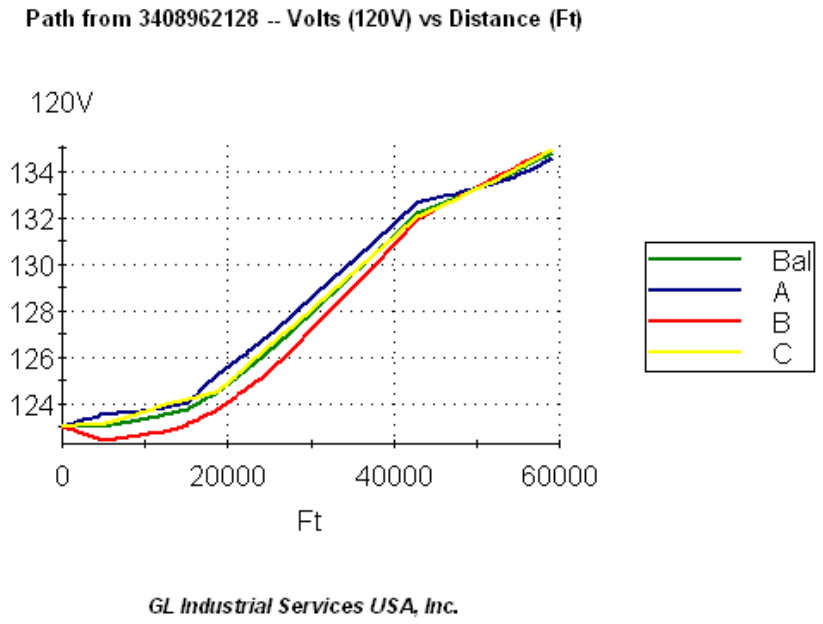
Although the load on the Los Chavez Substation transformer is less than the rated output of the project, the difference is approximately 4 MW, therefore no transmission related issues are anticipated to be associated with Project Los Chavez.

4.2 Screen for PV system impacts associated with power factor setting

The electric distribution system was screened to determine if there are any adverse impacts associated with Project Los Chavez injecting energy. Project Los Chavez was evaluated operating at a 100% power factor to determine if system criteria limits were violated. The system was evaluated with and without Project Los Chavez for maximum and minimum load during normal and contingent conditions. The evaluation with Project Los Chavez operating at 100% power factor for maximum load during normal conditions shows that the distribution system voltage is above the ANSI C84.1 Range A upper limit and is unacceptable.

For normal conditions, voltage for the feeder daylight hours maximum load for 2010 with Project Chavez turned ON, per the SynerGEE model is shown in Graph 1.

Graph 1 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to Project Los Chavez POI for daylight hours maximum load on August 15, 2010. Project Los Chavez is ON, 100% power factor.



The model voltages at the point of interconnection are:
Phase A – 134.6 volts Phase B – 135 volts Phase C – 134.9 volts Balanced – 134.8 volts

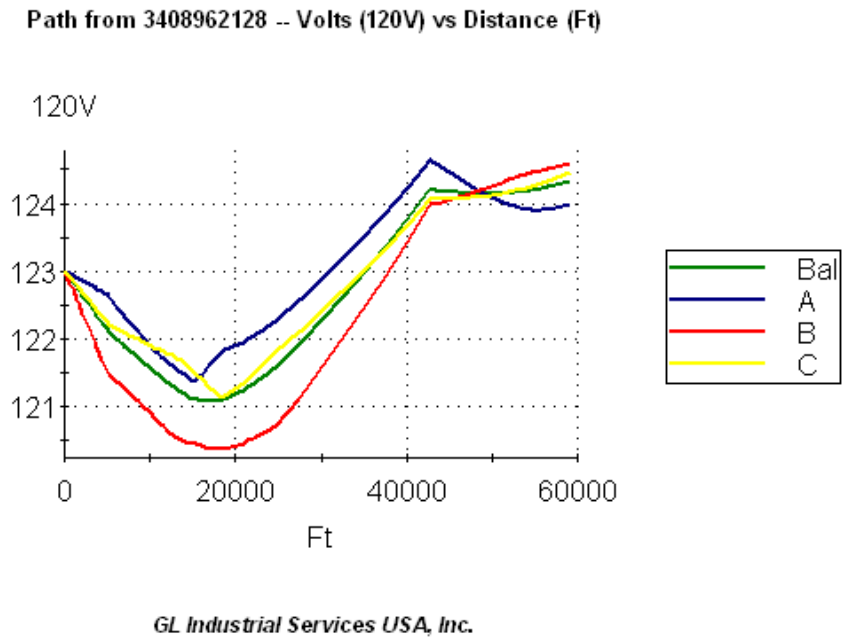
The voltages at Project Los Chavez POI are above the PNM voltage criteria ANSI C84.1 Range A upper limit and are unacceptable. This model is based on the 1200 KVAR switched capacitor bank on Los Chavez Feeder 12 being energized.

Project Los Chavez does have an adverse impact on the PNM electric distribution system when operating at 100% (unity) power factor. Voltage control utilizing a different power factor setting of the Project is necessary.

Additional scenario's reviewed by this study define an inverter based distributed generation facility operating with a power factor other then unity to be a facility that is absorbing or importing reactive power at the POI. Inverter control systems can be adjusted to allow the PV system to absorb reactive power (Vars) from the distribution system. Recommendations to absorb reactive power at the POI, to mitigate the Project voltage rise impact on the electric distribution system, will be included in all remaining operating conditions to review the ability of the facility to maintain ANSI C84.1 criteria limits.

Setting Project Los Chavez 6 MW PV system to a 96% power factor such that in the Project is injecting 5,760 KW into the distribution system and absorbing 1,680 KVAR from the distribution system is required to mitigate voltages above the ANSI C84.1 criteria limits. Graph 2 is for the same condition as shown in Graph 1 except Project Los Chavez is modeled with a 96% power factor.

Graph 2 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to Project Los Chavez POI for daylight hours maximum load on August 15, 2010. Project Los Chavez is ON, 96% power factor importing VARs.



The model voltages at the point of interconnection are:
Phase A – 124.0 volts Phase B – 124.6 volts Phase C – 124.5 volts Balanced – 124.3 volts

The voltages on Los Chavez Feeder 12 for normal conditions with Project Los Chavez turned ON and operating at a 96% power factor importing VARs are within the PNM voltage criteria of ANSI C84.1 Range A and are acceptable. This model is based on the 1200 KVAR switched capacitor bank on Los Chavez Feeder 12 being energized.

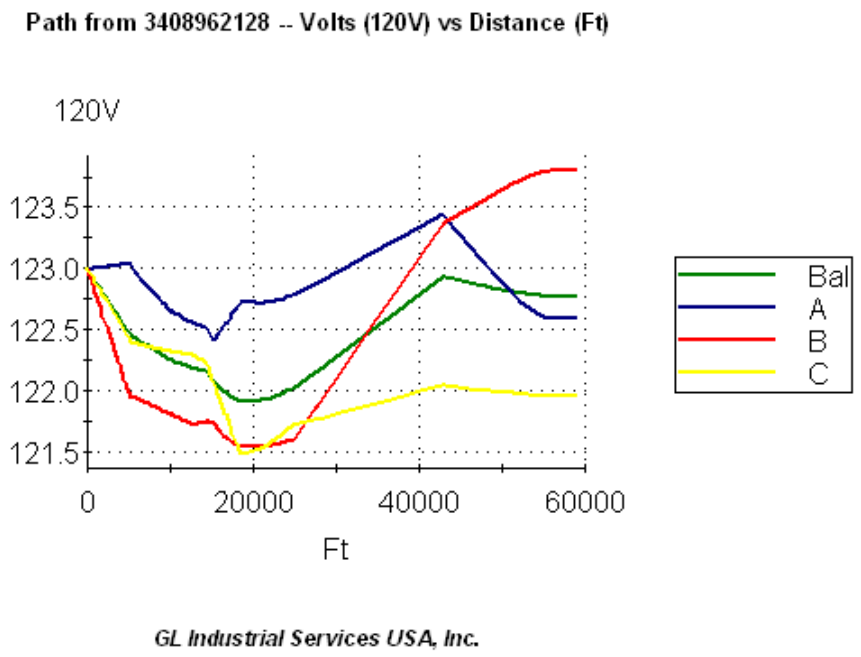
Distribution Planning recommends that Project Los Chavez be operated at a fixed power factor of 96% such that the Project is injecting 5,760 KW into the distribution system at the POI and absorbing 1,680 KVAR from the distribution system at the POI. This power factor setting will be used in further analysis of Project Los Chavez within this report.

4.3 Voltage impacts for maximum daylight hours load for normal configuration

The Los Chavez Feeder 12 voltage for the feeder daylight hours maximum load for 2010 with and without Project Los Chavez, per the SynerGEE model, are shown in Graphs 3 and 4.

Larger customer loads on the feeder were modeled using actual load values from the daylight hours maximum date and time.

Graph 3 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to Project Los Chavez POI for daylight hours maximum load on August 15, 2010. Project Los Chavez is OFF.

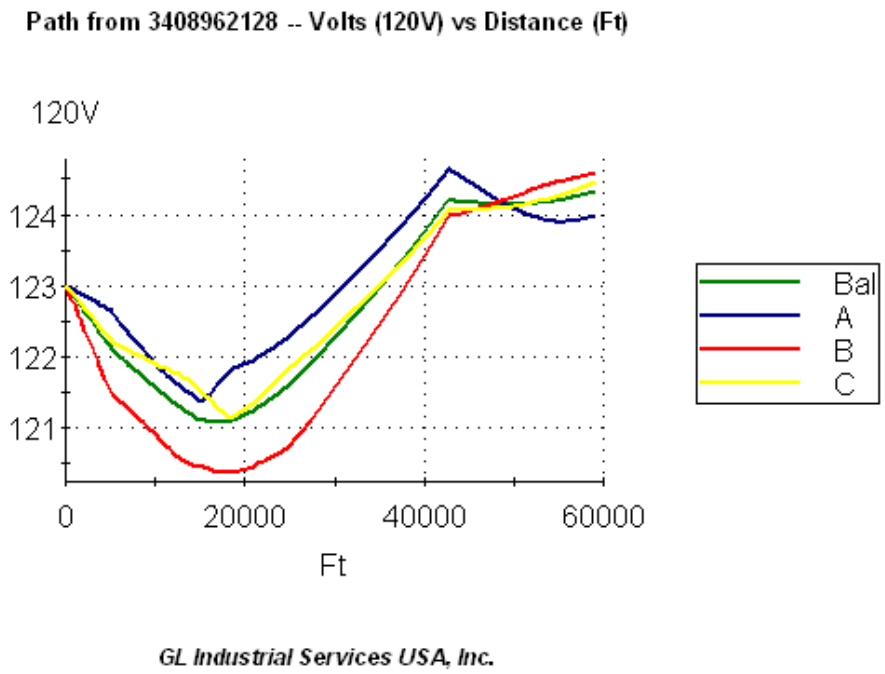


The model voltages at the point of interconnection are:

Phase A – 122.6 volts Phase B – 123.8 volts Phase C – 122.0 volts Balanced – 122.8 volts

The voltages on Los Chavez Feeder 12 prior to the installation of Project Los Chavez are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to Project Los Chavez POI for daylight hours maximum load on August 15, 2010. Project Los Chavez is ON, 96% power factor importing VARs.



The model voltages at the point of interconnection are:

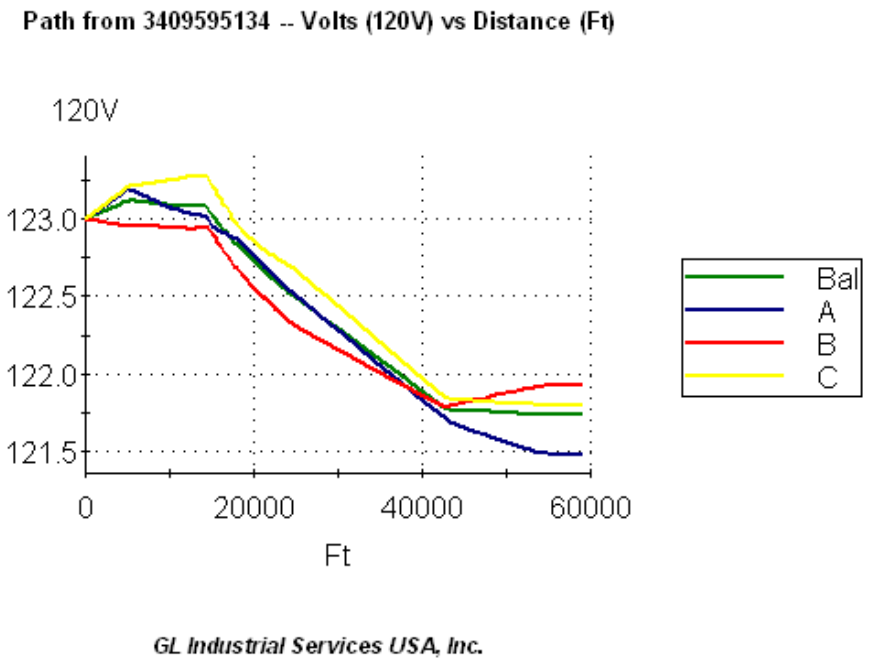
Phase A – 124.0 volts Phase B – 124.6 volts Phase C – 124.5 volts Balanced – 124.3 volts

The voltages on Los Chavez Feeder 12 after the installation of Project Los Chavez operating at 96% power factor importing VARs are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4 Voltage impacts for minimum daylight hours load for normal configuration

The Los Chavez Feeder 12 voltage for the feeder daylight hours minimum load for 2010 with and without Project Los Chavez, per the SynerGEE model, are shown in Graphs 5 and 6. Larger customer loads on the feeder were modeled using actual load values from the daylight hours minimum date and time.

Graph 5 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to the Project Los Chavez POI for daylight hours minimum load on September 23, 2010. Project Los Chavez is OFF.

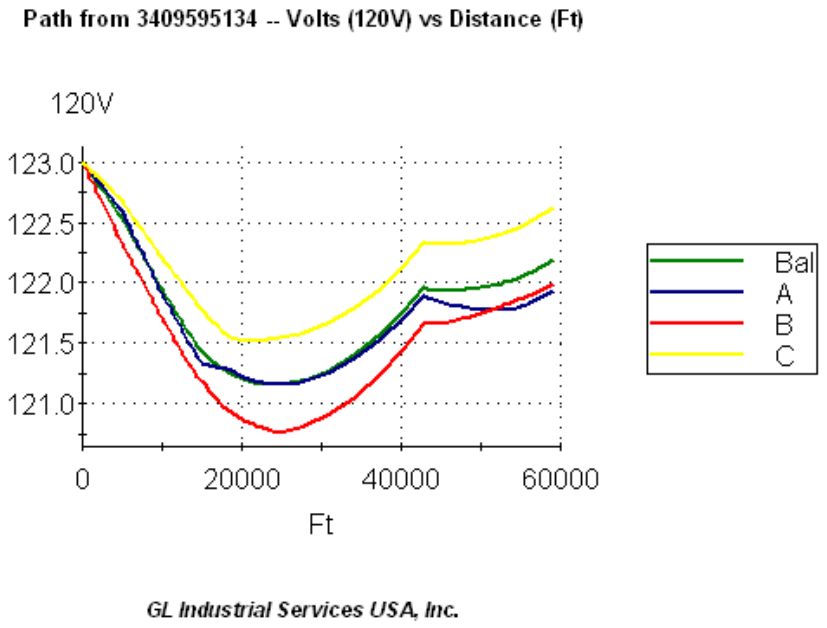


The model voltages at the point of interconnection are:

Phase A – 121.5 volts Phase B – 121.9 volts Phase C – 121.8 volts Balanced – 121.7 Volts.

The voltages on Los Chavez Feeder 12 prior to the installation of Project Los Chavez are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 6 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to the Project Los Chavez POI for daylight hours minimum load on September 23, 2010. Project Los Chavez is ON, 96% power factor importing VARs.



The model voltages at the point of interconnection are:
Phase A – 121.9 volts Phase B – 122.0 volts Phase C – 122.6 volts Balanced – 122.2 volts.

The voltages on Los Chavez Feeder 12 after the installation of Project Los Chavez operating at 96% power factor importing VARs are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5 Voltage impacts for maximum daylight hours load for contingency configuration

Presently, there are two possible scenarios for contingency configuration that Project Los Chavez can contribute to. The first is for the loss of Los Chavez Substation, the second is for the loss of San Clemente Substation.

Table 5 shows the load data used for the contingency evaluations. Table 5 shows the 2010 maximum and minimum daylight hours loading on San Clemente Feeder 12.

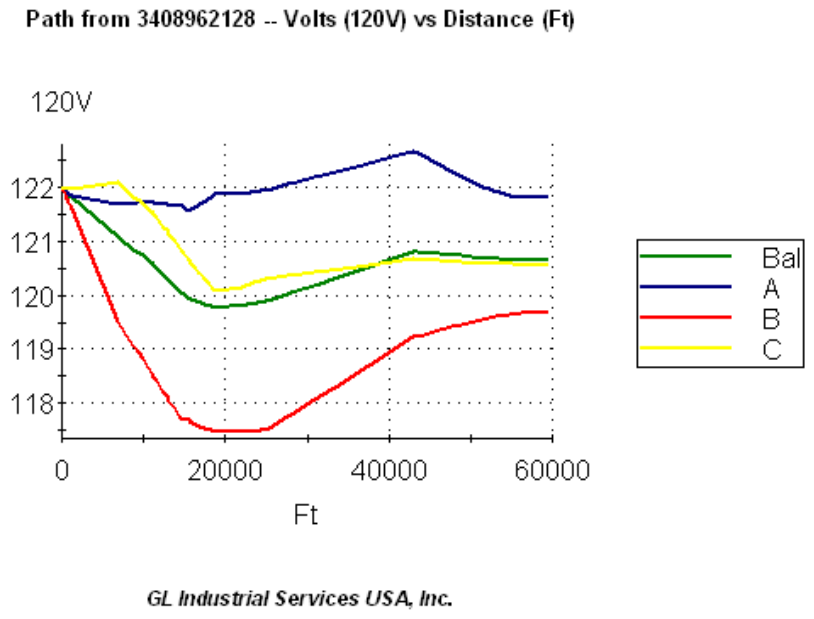
Table 5 *– San Clemente Feeder 12 max/min Daylight Hours Load*

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
July 19, 2010	5 PM	3,704	63	3,705	99.9	161	166	178
Sept. 12, 2010	7 AM	1,488	-211	1,503	-99.0	63	70	71

4.5.1 Contingency configuration – Loss of Los Chavez Substation, maximum load

For the loss of the Los Chavez Substation, 100% of Los Chavez Feeder 12 is transferred to San Clemente Substation through 47% of San Clemente Feeder 12. Voltage for the feeder daylight hours maximum load for 2010 with and without Project Los Chavez, per the SynerGEE model, are shown in Graphs 7 and 8. Larger customer loads on the feeder were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from San Clemente Substation to the Project Los Chavez point of interconnection (POI) is about 59,492 ft. or 11.3 miles.

Graph 7 – San Clemente Feeder 12 voltage drop from San Clemente Substation to the Project Los Chavez POI for the loss of Los Chavez Substation for daylight hours maximum load on August 15, 2010. Project Los Chavez is OFF.

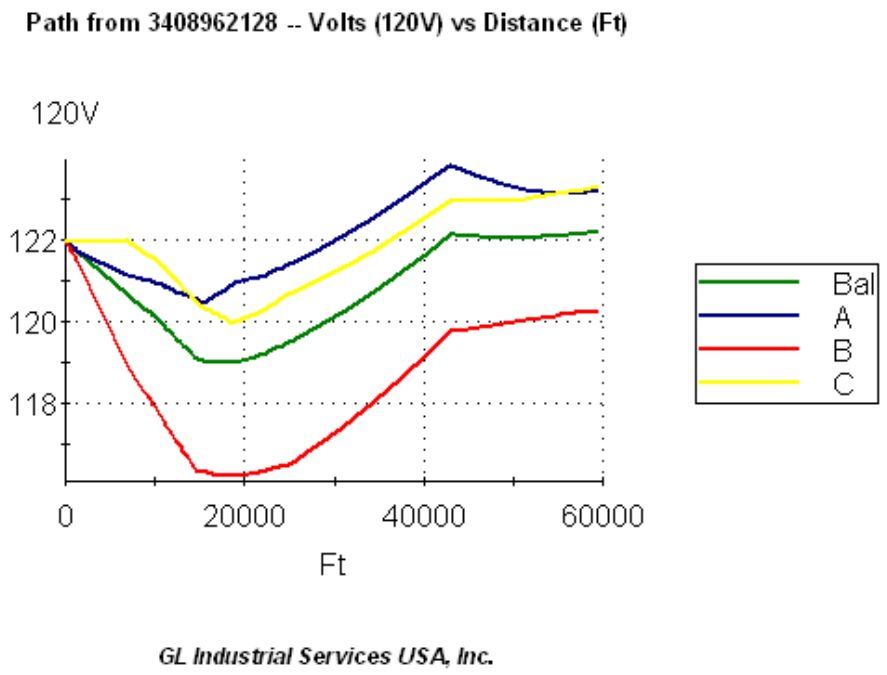


The model voltages at the point of interconnection are:

Phase A – 121.8 volts Phase B – 119.7 volts Phase C – 120.6 volts Balanced – 120.7 volts

The voltages on San Clemente Feeder 12 for the loss of Los Chavez Substation contingency prior to the installation of Project Los Chavez are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 8 – San Clemente Feeder 12 voltage drop from San Clemente Substation to the Project Los Chavez POI for the loss of Los Chavez Substation for daylight hours maximum load on August 15, 2010. Project Los Chavez is ON, at 96% power factor importing VARs.



The model voltages at the point of interconnection are:

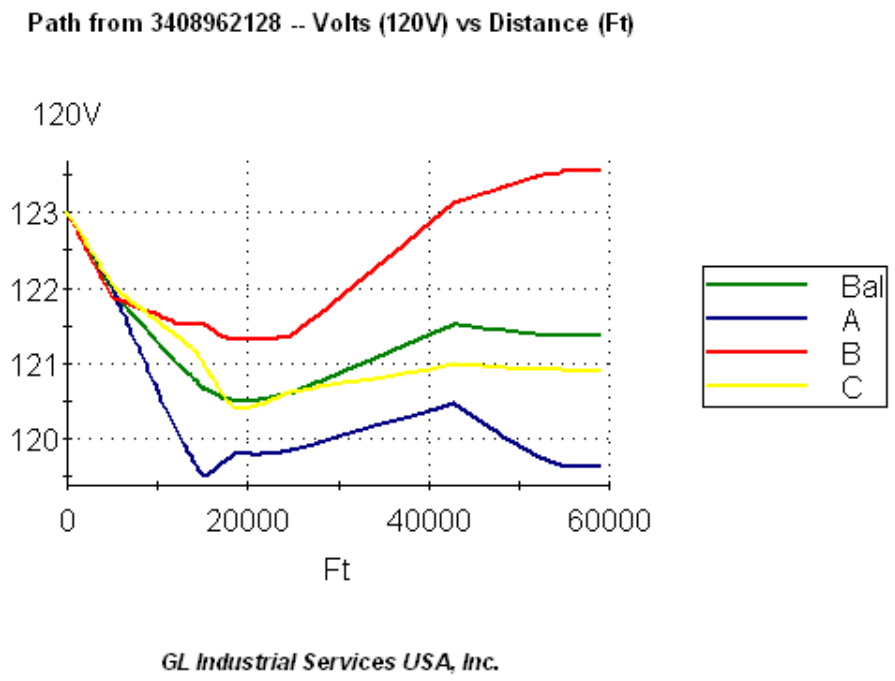
Phase A – 123.3 volts Phase B – 120.3 volts Phase C – 123.3 volts Balanced – 122.3 volts

The voltages on San Clemente Feeder 12 for the loss of Los Chavez Substation contingency after the installation of Project Los Chavez operating at 96% power factor importing VARs are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5.2 Contingency configuration – Loss of San Clemente Substation, maximum load

For the loss of the San Clemente Substation, 20% of San Clemente Feeder 12 is transferred to 100% of Los Chavez Feeder 12. Voltage for the feeder daylight hours maximum load for 2010 with and without Project Los Chavez, per the SynerGEE model, are shown in Graphs 9 and 10. Larger customer loads on the feeder were modeled using actual load values from the daylight hours maximum date and time. The circuit distance from Los Chavez Substation to the Project Los Chavez POI is the same as was stated earlier for normal configuration.

Graph 9 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to the Project Los Chavez POI for the loss of San Clemente Substation for daylight hours maximum load on August 15, 2010. Project Los Chavez is OFF.

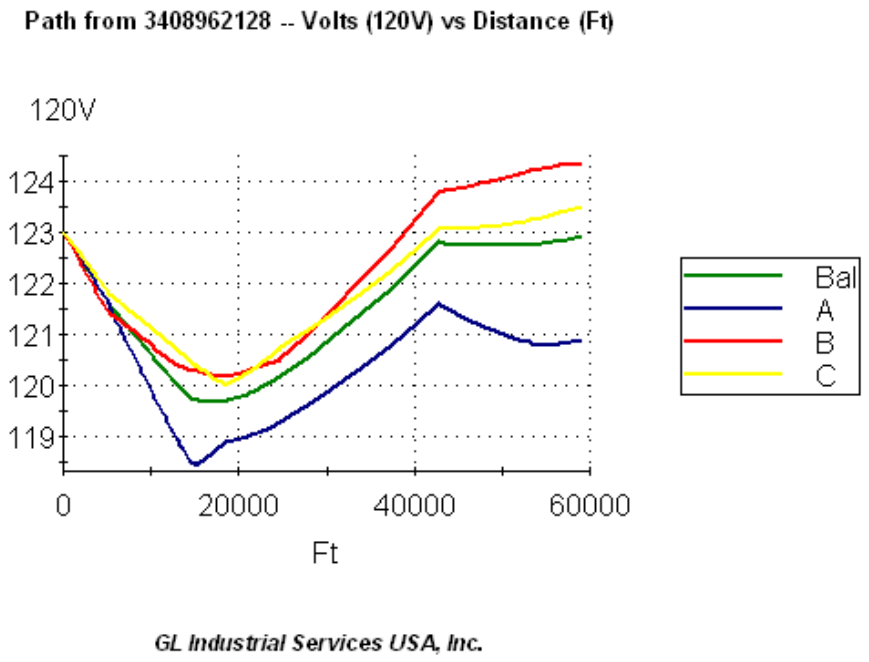


The model voltages at the point of interconnection are:

Phase A – 119.6 volts Phase B – 123.6 volts Phase C – 120.9 volts Balanced – 121.4 volts

The voltages on Los Chavez Feeder 12 for the loss of San Clemente Substation contingency prior to the installation of Project Los Chavez are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 10 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to the Project Los Chavez POI for daylight hours maximum load on August 15, 2010. Project Los Chavez is ON, at 96% power factor importing VARs.



The model voltages at the point of interconnection are:

Phase A – 120.9 volts Phase B – 124.4 volts Phase C – 123.5 volts Balanced – 122.9 volts

The voltages on Los Chavez Feeder 12 for the loss of Los Chavez Substation contingency after the installation of Project Los Chavez operating at 96% power factor importing VARs are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

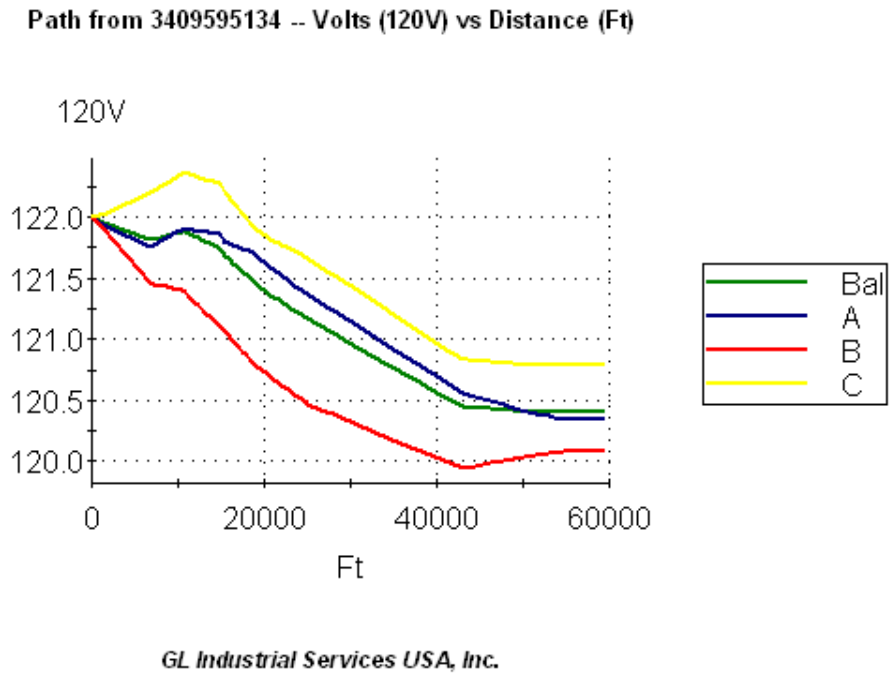
4.6 Voltage impacts for minimum daylight hours load for contingency configuration

4.6.1 Contingency configuration – Loss of Los Chavez Substation, minimum load

For the loss of the Los Chavez Substation, 100% of Los Chavez Feeder 12 is transferred to San Clemente Substation through 47% of San Clemente Feeder 12. Voltage for the feeder daylight hours minimum load for 2010 with and without Project Los Chavez, per the SynerGEE model,

are shown in Graphs 11 and 12. Larger customer loads on the feeder were modeled using actual load values from the daylight hours minimum date and time.

Graph 11 – San Clemente Feeder 12 voltage drop from San Clemente Substation to the Project Los Chavez POI for the loss of Los Chavez Substation for daylight hours minimum load on September 23, 2010. Project Los Chavez is OFF.

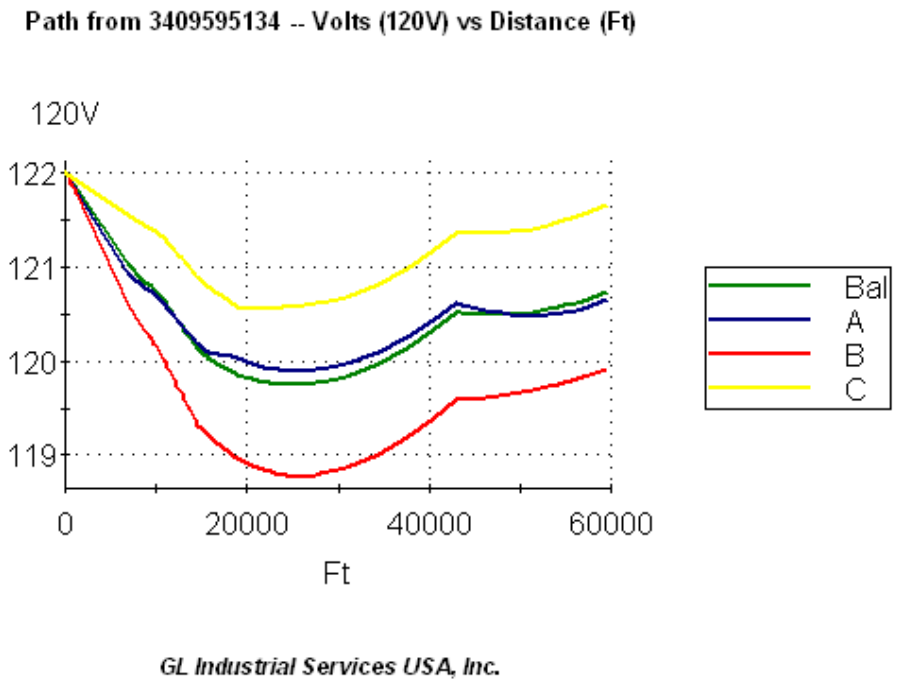


The model voltages at the point of interconnection are:

Phase A – 120.3 volts Phase B – 120.1 volts Phase C – 120.8 volts Balanced – 120.4 volts.

The voltages on San Clemente Feeder 12 for the loss of Los Chavez Substation contingency prior to the installation of Project Los Chavez are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 12 – San Clemente Feeder 12 voltage drop from San Clemente Substation to the Project Los Chavez POI for the loss of Los Chavez Substation for daylight hours minimum load on September 23, 2010. Project Los Chavez is ON, at 96% power factor importing VARs.



The model voltages at the point of interconnection are:

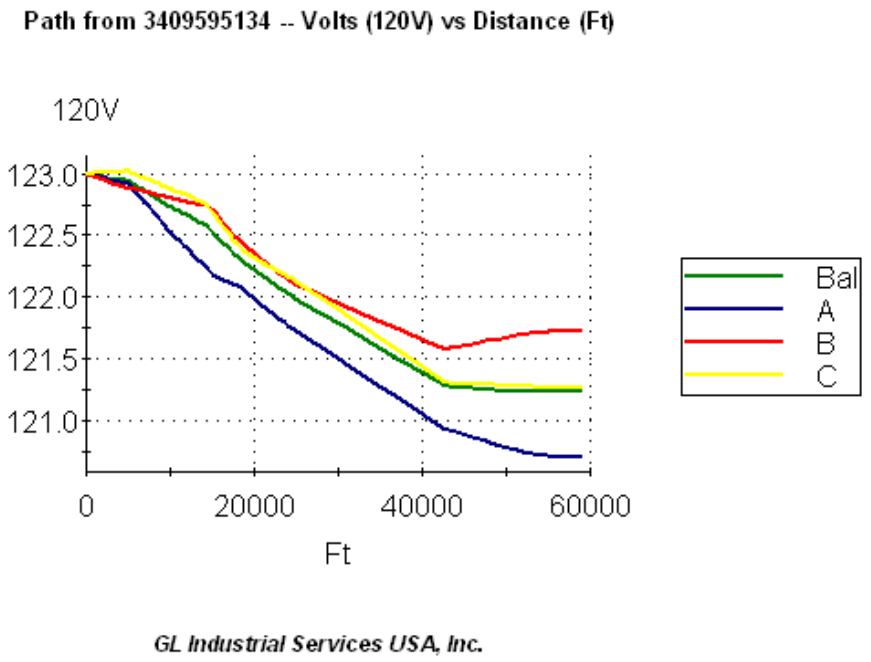
Phase A – 120.7 volts Phase B – 119.9 volts Phase C – 121.7 volts Balanced – 120.7 volts

The voltages on San Clemente Feeder 12 for the loss of Los Chavez Substation contingency after the installation of Project Los Chavez operating at 96% power factor importing VARs are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.6.2 Contingency configuration – Loss of San Clemente Substation, minimum load

For the loss of the San Clemente Substation, 20% of San Clemente Feeder 12 is transferred to 100% of Los Chavez Feeder 12. Voltage for the feeder daylight hours minimum load for 2010 with and without Project Los Chavez, per the SynerGEE model, are shown in Graphs 13 and 14. Larger customer loads on the feeder were modeled using actual load values from the daylight hours minimum date and time. The circuit distance from Los Chavez Substation to the Project Los Chavez POI is the same as was stated earlier for normal configuration.

Graph 13 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to the Project Los Chavez POI for the loss of San Clemente Substation for daylight hours minimum load on September 23, 2010. Project Los Chavez is OFF.

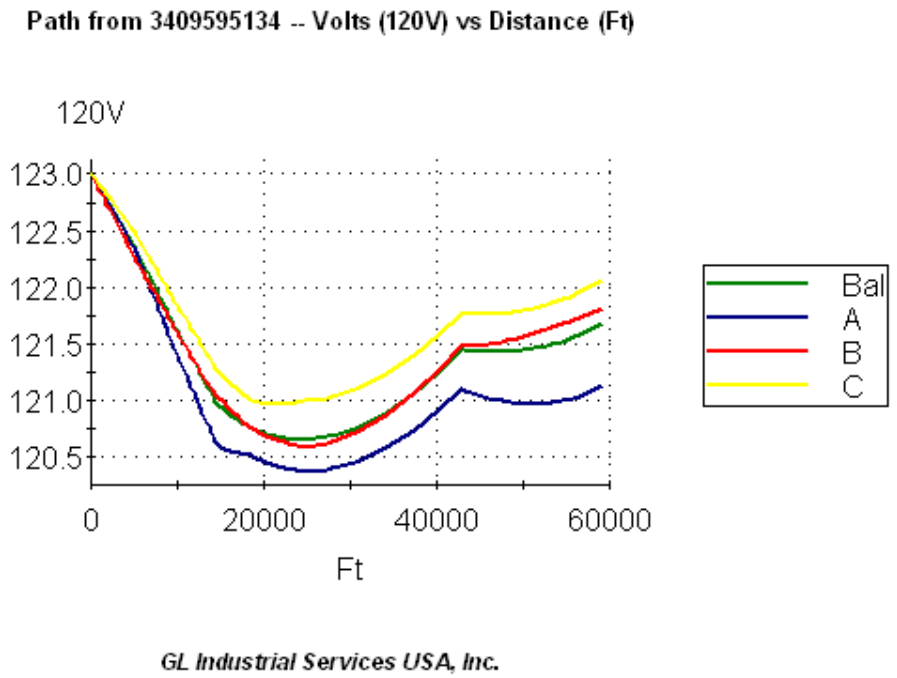


The model voltages at the point of interconnection are:

Phase A – 120.7 volts Phase B – 121.7 volts Phase C – 121.3 volts Balanced – 121.2 volts

The voltages on Los Chavez Feeder 12 for the loss of San Clemente Substation contingency prior to the installation of Project Los Chavez are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 14 – Los Chavez Feeder 12 voltage drop from Los Chavez Substation to the Project Los Chavez POI for the loss of San Clemente Substation for daylight hours minimum load on September 23, 2010. Project Los Chavez is ON, at 96% power factor importing VARs.



The model voltages at the point of interconnection are:

Phase A – 121.1 volts Phase B – 121.8 volts Phase C – 122.1 volts Balanced – 121.7 volts

The voltages on Los Chavez Feeder 12 for the loss of Los Lunas Substation contingency after the installation of Project Los Chavez operating at 96% power factor importing VARs are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion, the output from Project Los Chavez operating at 96% power factor importing VARs does cause the voltage on Los Chavez Feeder 12 and on San Clemente Feeder 12 for contingency conditions to increase. However, the voltage stays within the PNM criteria of ANSI C84.1 and is acceptable.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Los Chavez is served by Los Chavez Feeder 12, and there are two voltage regulators installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

There are two voltage regulators presently installed on Los Chavez Feeder 12. The first is a three phase regulator, VR0V, set with no reverse mode at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts) for forward operation. In the normal forward direction, it will operate to boost the voltage if the voltage at the load side terminals of the regulator is below 120.5 volts and will reduce the voltage at the load side terminals of the regulator if above 123.5. The second is a single phase regulator, VR32V, which will be removed when the line is upgraded to three phase to support the interconnection of Project Los Chavez.

As seen in Tables 6 -9, the SynerGEE modeling shows the LTC changed 2 positions for 6,000 KVA source on the feeder for high or low load periods. This LTC operation is not considered an adverse impact.

Project Los Chavez was modeled as a source on Los Chavez Substation connected to the end of Los Chavez Feeder 12. The SynerGEE model included the substation transformer and Los Chavez Feeders 11 and 12. The substation bus voltage and load tap changer position for maximum daylight hours load for 2010 with and without Project Los Chavez 6MW, per the SynerGEE model, are shown in Tables 6 and 7.

Table 6 – ***Los Chavez Substation with Project Los Chavez OFF for daylight hours maximum load on August 15, 2010***

	LOS CHAVEZ SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.6	122.6	122.2	122.5
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 6. The voltages at Los Chavez Substation prior to the installation of Project Los Chavez are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 7 – ***Los Chavez Substation with Project Los Chavez ON, at 96% power factor importing VARs for daylight hours maximum load on August 15, 2010***

	LOS CHAVEZ SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.9	122.9	122.7	122.8
LTC position	2 raise	2 raise	2 raise	

The model voltages at the substation bus are shown in Table 7. The voltages at Los Chavez Substation after the installation of Project Los Chavez operating at 96% power factor importing VARs are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The Los Chavez Feeder 12 voltage for the feeder minimum daylight hours load for 2010 with and without Project Los Chavez, per the SynerGEE model, are shown in Graphs 8 and 9.

Table 8 – ***Los Chavez Substation with Project Los Chavez OFF for daylight hours minimum load on September 23, 2010***

	LOS CHAVEZ SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	123.1	123.2	123.2	123.1
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 8. The voltages at Los Chavez Substation prior to the installation of Project Los Chavez are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 9 – ***Los Chavez Substation with Project Los Chavez ON, at 96% power factor importing VARs for daylight hours minimum load on September 23, 2010***

	LOS CHAVEZ SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.3	122.4	122.5	122.4
LTC position	1 raise	1 raise	1 raise	

The model voltages at the substation bus are shown in Table 9. The voltages at Los Chavez Substation after the installation of Project Los Chavez at 96% power factor importing VARs are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Los Chavez Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of Project Los Chavez output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Los Chavez Substation bus was fixed at 123 volts with and without Project Los Chavez output for maximum and minimum load periods. Table 10 summarizes the balanced voltage and the calculated voltage flicker. Table 11 is based on the GE flicker graph.

Table 10 – ***Voltage flicker at the POI due to Project Los Chavez***

	Project Los Chavez POI Bus Voltage	
	Minimum	**Maximum**
Without Project	121.7	122.8
With Project	122.2	124.3
% Voltage Flicker	**.41**	**1.22**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 11 – ***Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
.41	20/minute	No Irritation
1.22	6/hour	10/minute

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 10 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 11. Results are less than the 6% criteria; therefore distribution voltage flicker resulting from changes in Project Los Chavez output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Los Chavez POI to the substation were reviewed using the SynerGEE feeder model with and without Project Los Chavez's maximum output of 6,000 KVA AC.

There were no conductor loading problems from the POI to the substation on Los Chavez Feeder 12 with or without Project Los Chavez.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Los Chavez Feeder 12 has one 1200 KVAR RCCS controlled capacitor bank and two 600 KVAR fixed capacitor banks. The August 2010 peak load on the feeder was 4,139 KW – j 328 KVAR or 4,152 KVA at a 99.7 leading power factor (-99.7 PF). All three capacitor banks were energized during the peak load period. Project Los Chavez operating at 96% power factor importing VARs would change the apparent feeder loading to -1,621 KW + j 1,352 KVAR or 2,110 KVA at 76.8% leading power factor (-76.8% PF). The positive KVAR indicates that Los Chavez Feeder 12 is exporting VARs to Project Los Chavez. This power factor value exceeds the RCCS power factor control point, but all capacitors are energized prior to this condition, therefore any issues addressed would be driven by pre-existing conditions. Should the RCCS system switch the 1,200 KVAR capacitor bank off, the minimum voltage on the circuit drops to 116 volts, which is in Range B, but acceptable. There are no issues associated with operating Project Los Chavez at 96% power

factor importing VARs during maximum conditions. The power factor does indeed appear to become worse, but the SynerGEE model shows that there are no voltage or thermal problems associated with this condition.

This study also examined switching RCCS controlled capacitor banks under minimum load conditions to see what affect this would have on the system with the inverter operating at 96% power factor importing VARs. At minimum feeder load, with the RCCS capacitor bank offline, the voltage on the feeder is within the PNM voltage criteria (ANSI C84.1) at the POI and is acceptable. At minimum feeder load, if the RCCS controlled capacitor bank were to be switched on with Project Los Chavez operating at 96% power factor importing VARs, the feeder voltage exceeds the PNM criteria of ANSI C84.1 at 128.98 volts. This condition is not acceptable, but is not a result of the addition of Project Los Chavez. At minimum feeder load with no PV installed, and the RCCS capacitor bank is switched online, the feeder voltage exceeds the PNM Criteria of ANSI C84.1 at 127.66 volts. Since this capacitor bank is at the end of the feeder and used to support low voltage at the end of the feeder, it is highly unlikely to switch on during minimum loading conditions.

For the loss of Los Chavez Substation, a portion of San Clemente Feeder 12 provides backup support to Los Chavez Feeder 12. While San Clemente Feeder 12 is providing backup support to the area, there are two 1,200 KVAR RCCS capacitor banks and two 600 KVAR fixed capacitor banks on the feeder. During the contingency analysis for the loss of Los Chavez Substation, all capacitor banks were assumed to be on for the peak load timeframe and the RCCS capacitor banks were assumed to be off for the minimum load timeframe. For this analysis the voltages are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable for these configurations. This study also examined switching the RCCS controlled capacitor banks under maximum and minimum load conditions to see what affect this would have on the system with the inverter operating at 96% power factor importing VARs. For peak conditions, switching either one or both of the RCCS capacitor banks off will cause the voltages on the feeder to drop below the ANSI C84.1 voltage criteria, but this is not the result of the addition of Project Los Chavez. The SynerGEE model shows the minimum voltage to drop to unacceptable limits without Project Los Chavez if either or both of the RCCS capacitor banks are de-energized at peak conditions. For minimum conditions, switching on the RCCS capacitor, C140V, which is close to the sub, does not result in any unacceptable voltage conditions on the feeder. For minimum conditions, switching RCCS capacitor, C145V, which is

at the end of the feeder, or both of the RCCS capacitor banks on will cause the voltages to rise above the ANSI C84.1 voltage criteria, but this is not the result of the addition of Project Los Chavez. The SynerGEE model shows the maximum voltage on the feeder to rise above acceptable limits without Project Los Chavez if C145V or both of the RCCS capacitor banks are energized during minimum loading conditions. Since the RCCS capacitor bank, C145V, is at the end of the feeder and used to support low voltage at the end of the feeder, it is highly unlikely to switch off during maximum loading conditions or on during minimum loading conditions.

For the loss of San Clemente Substation, 20% of San Clemente Feeder 12 is backed up by Los Chavez Feeder 12. While Los Chavez Feeder 12 is providing backup support to the area, there is one 1,200 KVAR RCCS capacitor bank and two 600 KVAR fixed capacitor banks on the feeder. During the contingency analysis for the loss of San Clemente Substation, all capacitor banks were assumed to be on for the peak load timeframe and the RCCS capacitor bank was assumed to be off for the minimum timeframe. For this analysis the voltages are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable for these configurations. This study also examined switching the RCCS controlled capacitor banks under maximum and minimum load conditions to see what affect this would have on the system with the inverter operating at 96% power factor importing VARs. For peak conditions, switching the RCCS capacitor bank off will cause the voltages to drop to 113.7 volts at the POI, and the minimum voltage on the feeder drops to 112.42 volts, this exceeds the voltage criteria, but this is not the result of the addition of Project Los Chavez. The SynerGEE model shows the minimum voltage on the feeder at 112.83 volts without Project Los Chavez if the RCCS capacitor bank is de-energized at peak conditions. For minimum conditions, switching the RCCS capacitor bank on will cause the voltages to rise to 128.3 volts at the POI, and to 128.51 volts on the feeder, which exceeds the voltage criteria, but this is not the result of the addition of Project Los Chavez. The SynerGEE model shows the maximum voltage on the feeder is 127.51 volts without Project Los Chavez if the RCCS capacitor bank is energized during minimum loading conditions. Since the RCCS capacitor bank is at the end of the feeder and used to support low voltage at the end of the feeder, it is highly unlikely to switch off during maximum loading conditions or on during minimum loading conditions.

9.0 PROTECTION

9.1 Normal Configuration – Service from Los Chavez Substation Feeder 12

Los Chavez Substation feeder 12 is protected by a 1200 amp breaker in metal clad switchgear with a GE, IAC77 phase overcurrent relay and an IAC53 ground overcurrent relay. There is also a GE, ACR reclosing relay. The switchgear bus and feeder backup protection is an ABB, DPU2000R phase relay and an ABB, DPU2000R ground relay. The transformer protection is an ABB, TPU2000R differential relay. The Los Chavez Project PV system is connected to the system approximately 11.22 miles from the substation. Approximately 3.53 miles from the Los Chavez Project PV system, there is a three phase electronic recloser. There is also a 25 amp sectionalizer that is approximately 8.66 miles from the Los Chavez PV Project.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder.

The Los Chavez Project does not require any system protection improvements to be made to the Los Chavez Substation feeder 12 under normal configuration.

9.2 Normal Feeder as a Backup Feeder – Los Chavez Feeder 12 picks up San Clemente Feeder 12

The Los Chavez Project PV system is connected to the system approximately 11.22 miles from the substation. Approximately 3.53 miles from the Los Chavez Project PV system, there is a three phase electronic recloser. There is also a 25 amp sectionalizer that is approximately 8.66 miles from the Los Chavez PV Project.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder.

The Los Chavez Project does not require any system protection improvements to be made to the Los Chavez Substation feeder 12 under normal feeder as a backup feeder.

9.3 Contingency Configuration – San Clemente Feeder 12 picks up Los Chavez Feeder 12

San Clemente Substation feeder 12 is protected by a 1200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 ground overcurrent relay. There is also a Westinghouse, RC reclosing relay. The transformer is fused on the primary with SMD-2B, 150E fuses. The Los Chavez Project PV system will be approximately 11.27 miles from the substation. There is a three phase electronic recloser 3.53 miles away, and a 25 amp sectionalizer 8.66 miles from the Los Chavez Project PV system.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 520 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The study first looked at the impact to the recloser. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes miscoordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection miscoordination issues on the feeder.

The Los Chavez Project does not require any system protection improvements to be made to the San Clemente Substation feeder 12 under contingency configuration.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Los Chavez output exceeds the 2010 maximum and minimum load on Los Chavez Feeder 12 during daylight hours. No Los Chavez Feeder 12 equipment overloads were identified.

Project Los Chavez output exceeds the 2010 maximum and minimum load on San Clemente Feeder 12 during daylight hours. No San Clemente Feeder 12 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

The following cost estimates for communication have been developed:

ONE-TIME Equipment COST	$ 35,000
One-Time Labor Cost	$ 10,000
MONTHLY Recurring O&M	$ 3,500

The breakdown of the ONE-TIME Equipment cost:

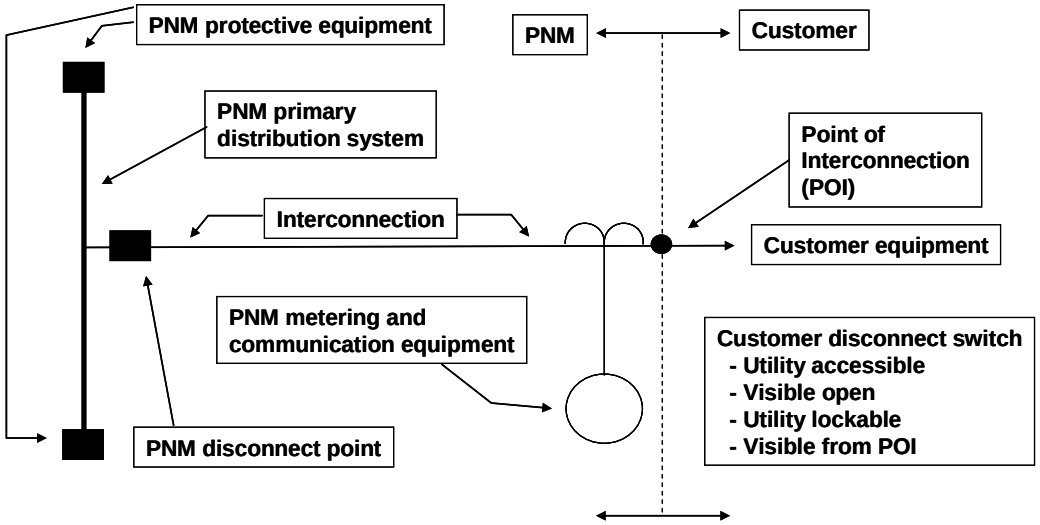
Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$ 20,000
Channel Bank Equipment	$ 10,000

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 2 is a one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 2 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



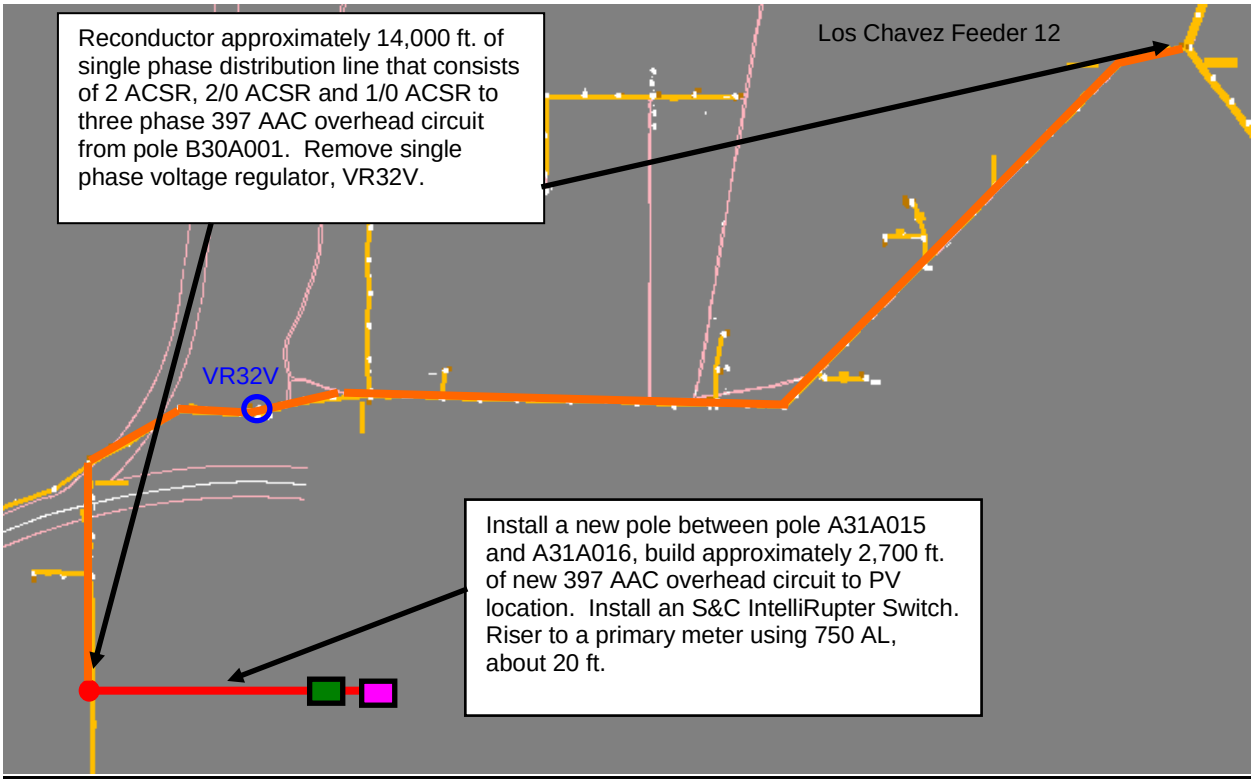
The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project Los Chavez to the PNM distribution system, a line extension is required. The interconnection consists of:

- Reconductor approximately 14,000 ft. of single phase distribution line that consists of 2 ACSR, 2/0 ACSR and 1/0 ACSR to three phase 397 AAC overhead circuit from pole B30A001 (See Figure 3).
- Remove single phase voltage regulator, VR32V (See Figure 3).
- Install a new pole between pole A31A015 and A31A016, build approximately 2,700 ft. of new 397 AAC overhead circuit to PV location (See Figure 3).
- Install One S&C IntelliRupter switch (See Figure 3).
- Install riser to primary meter, about 20 ft, using 750 AL (See Figure 3).

Figure 3 ***– Line Extension to connect Project Los Chavez to Los Chavez Feeder 12***



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 12.

Table 12 ***– Project Los Chavez Interconnection Cost***

	ESTIMATED COSTS 2010$
PNM disconnect point (Intellirupter)	$ 52,000
Interconnection (Line Construction)	$ 650,000
PNM Primary metering	$ 25,000
Communications	$ 45,000
Protection	$ 0
ROW	$ 31,000
TOTAL	**$ 803,000**

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This may also involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition is not expected to be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA). The NOA may also require the facility to operate at 96% power factor importing VARS as a condition to maintain interconnection to the EPS.

16.0 CONCLUSIONS

Project Los Chavez does have an adverse impact on the PNM distribution system when operating at 100% power factor. Voltage control must be maintained by operating at 96% power factor importing VARs. The Project location will result in an interconnection with Los Chavez Feeder 12. When operating at a 96% power factor importing VARs, analysis shows voltages will remain within the PNM criteria of ANSI C84.1. There is one remotely controlled capacitor bank on the feeder associated with Project Los Chavez. The automatic control of voltage by the substation LTC may cause the LTC to operate, but this is not anticipated to be an adverse effect. The Project output will cause a flow of electricity from the distribution system through the substation transformer, the difference is less than 5 MW, and therefore no transmission related issues are anticipated. Analysis showed that the Project output did not cause conductor ratings to be exceeded. Finally, analysis shows that Project Los Chavez output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Los Chavez and has determined that there are no adverse impacts associated with a 6,000 KVA AC source connected to Los Chavez Substation connected to Los Chavez Feeder 12 when operated at 96% power factor importing VARs.

Distribution Planning has determined that system upgrades are required to ensure that electric service to all customers on Los Chavez Substation is maintained within established PNM voltage, equipment and fault protection criteria.

Public Service Company of New Mexico Generation Planning and Development

Hondale 12 6,000 KVA PV Generation Project

Small Generator System Impact Study

(SGI-PNM-2010-13)

December 2010

Prepared by:

Public Service Company of New Mexico Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for Public Service Company of New Mexico Generation Planning and Development by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

Public Service Company of New Mexico Generation Planning and Development Department submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 6,000 KVA AC to the Public Service of New Mexico ("PNM") electric distribution primary system. The request is identified as Project Hondale and would be connected to Hondale Feeder 12. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures ("SGIP") for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study was performed by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts ("Distribution Planning").

The estimated cost of connecting Project Hondale to the electric distribution primary is:

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ 48,900	~ 16 week lead time ~ 3 days to build
Interconnection**	$ 18,100	~ 16 week lead time ~ 2 weeks to build
PNM metering	$ 16,100	~ 3 week lead time ~ 4 days to build
Right of Way	$ 2,600	
Protection***	$ 0	
Communication	$ 45,000	
Communication monthly O&M	$ 3,500	
TOTAL	**$ 135,200** **Plus monthly O&M of $3,500**	**5-6 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

The application notes the use of a Sunny Central ("SC") SMA 500CP inverter. The technical data notes for the SC SMA 500CP inverter was used to prepare this report. The data shows this inverter is presently not certified as UL 1741 complaint. The SC SMA 500CP inverter will have a 1,000V DC rating and is designed to meet UL 1741 compliance standards. Since UL testing is limited to 600V systems the project is requesting a variance to the UL 1741 compliance standard. Based on the manufacturer technical data the inverter is capable of operating at a power factor ranging from 90% lagging to 90% leading. Distribution Planning recommends the use of an inverter listed as UL 1741 complaint to insure, among other concerns, that the inverter will anti-island as recommended in IEEE 1547 guidelines. Any non-utility generation interconnection must also meet all other requirements as indicated in the SGIP application, Attachment 3. A complete field checkout of non-complaint equipment at the proposed facility is recommended before the facility can be considered certified for interconnection operation.

This Interconnection System Impact Study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the PNM distribution primary system. The photovoltaic ("PV") generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Distribution Planning performed a screening analysis of Project Hondale 6 MVA PV system operating at 100% (unity) power factor. The screening analysis determined there was an adverse impact on the PNM electric distribution system during an outage of Hondale Substation. Voltage control utilizing a different power setting can mitigate this adverse impact. There are two options to mitigate the adverse impact. Option 1 is to operate during all electric system conditions, normal and contingent, at a fixed 97% power factor with the Project injecting 5,820 KW into the electric distribution system at the Point of Interconnection ("POI") and absorbing 1,459 KVAR from the electric distribution system at the POI. Option 2 is establishment of an operating procedure to address the adverse impact.

Distribution Planning recommends that an operating procedure be developed and implemented to address identified adverse voltage impacts.

The Project location will result in an interconnection with Hondale Feeder 12 and analysis results were:

1. Establish an operating procedure to address identified adverse voltage impacts to ensure that distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds were found to not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may be energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not require the Hondale Feeder 12, Hondale Substation, Hermanas Feeder 12 or Hermanas Substation protection scheme be modified.
7. Project output may cause a flow of electricity from the distribution system through the Hondale or Hermanas Substation transformer. There is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Hondale and has determined that there are no adverse impacts associated with a 6,000 KVA source operating at 100% (unity) power factor during normal conditions. Project Hondale operating at a 100% (unity) power factor has an adverse impact on the PNM electric distribution system when Hermanas Feeder 12 is supporting Hondale Feeder 12 due to Hondale Substation being out-of-service. Voltage control utilizing a different power setting can mitigate this adverse impact. Establishment of an operating procedure is required to address this adverse impact.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Hondale Substation is maintained within established PNM voltage, equipment and fault protection criteria. Distribution Planning recommends that an operating procedure be developed and implemented to address identified adverse voltage impacts.

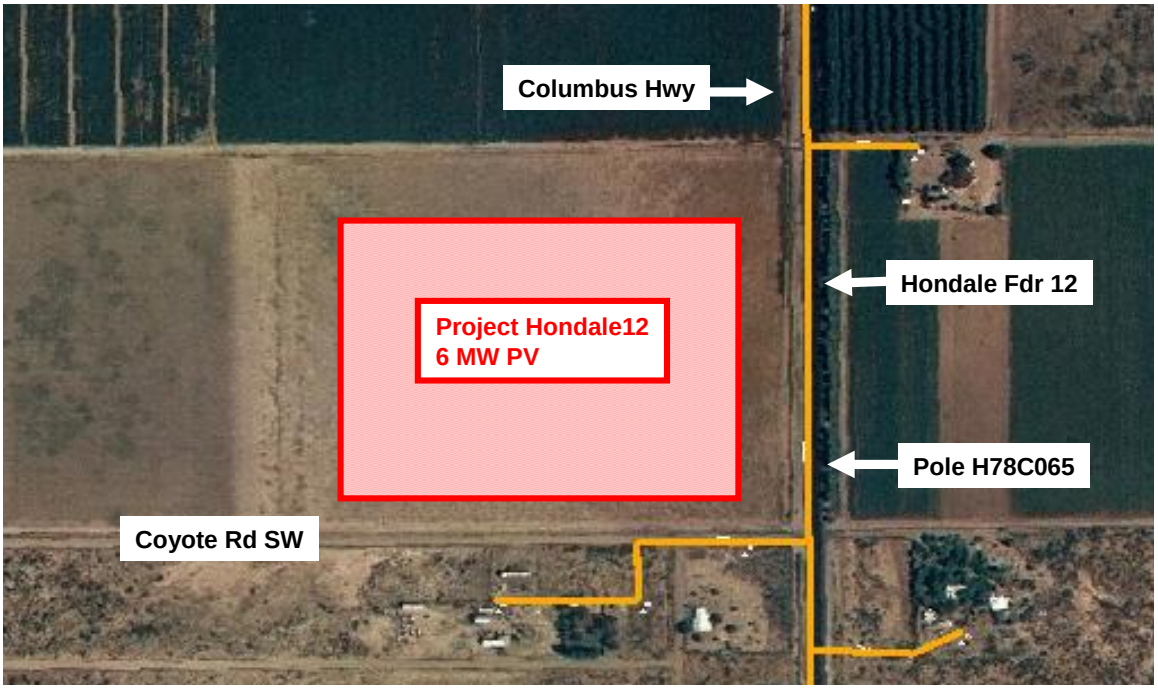
1.0 INTRODUCTION

The purpose of this Interconnection System Impact Study ("Study") is to determine electrical system impacts from a photovoltaic ("PV") electric generation source connected to the PNM distribution primary system identified as Project Hondale. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage and current produced by the PV equipment to AC voltage and current. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Hondale proposes to connect a 6,000 KVA AC PV facility to Hondale Substation Feeder 12 in Deming, NM. The Project will be located on the northwest corner of the Columbus Hwy and Coyote Rd intersection in Deming as shown in Figure 1. The circuit distance from Hondale Substation to the Project Hondale point of interconnection ("POI") is about 16,015 ft or 3.03 miles.

***Figure 1* – Project Hondale location**



3.0 SYSTEM CONFIGURATION

Project Hondale is connected to Hondale Substation Feeder 12. The Project is normally served from Hondale Feeder 12 with contingency backup provided by Hermanas Feeder 12. Table 1 shows the rating of Hondale and Hermanas Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Hondale	14.00	15.12	16.00	115-13.8
Hermanas	20.00	20.00	22.00	115-13.8

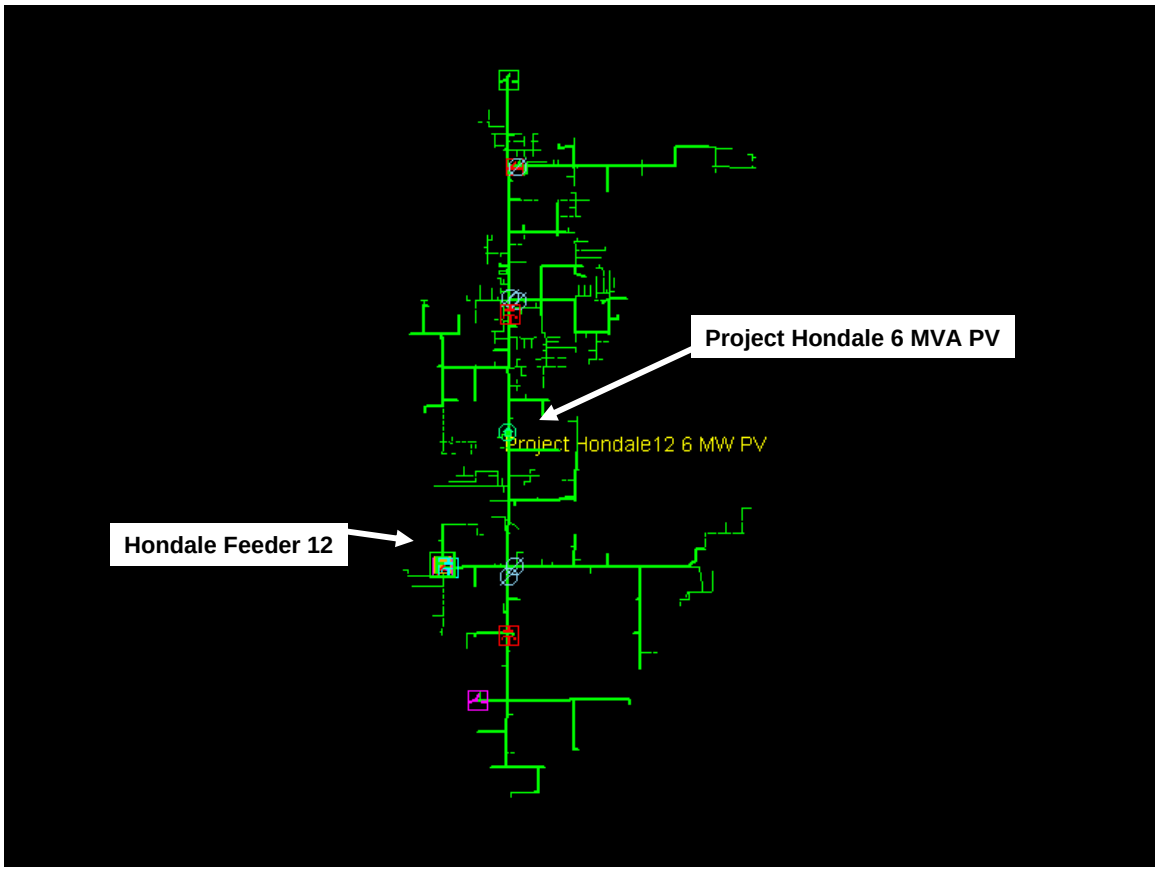
Table 2 shows the non-coincident peak 2010 peak summer loads for Hondale and Hermanas Substation and feeders.

***Table 2* – Summer 2009 (June-August) Non-coincident Peak Loads**

Feeder	Summer 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Hondale				
Hondale 11	2,842	946	2,995	94.9
Hondale 12	3,328	-1,116	3,510	-94.8
Hondale 13	0	0	0	0
Hondale Sub	5,902	-488	5,922	-99.7
Hermanas				
Hermanas 11	2,808	108	2,810	99.9
Hermanas 12	2,373	913	2,543	93.3
Hermanas 13	3,378	754	3,461	97.6
Hermanas 14	419	209	468	89.5
Hermanas Sub	8,542	1,759	8,721	97.9

Figure 2 is a picture of the distribution feeder model used in the GL Synergee analysis program.

Figure 2 ***- Synergee model of Hondale Feeder 12***



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on Hondale Feeder 12 and Hermanas Feeder 12 are shown in Table 3:

Table 3 ***- Max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Hondale 12								
July 30, 2009	5 PM	3,269	-1,235	3,495	-93.6	135	151	149
Jan 15, 2009	4 PM	700	-1,127	1,327	-52.8	51	60	55
Hermanas 12								
July 20, 2009	6 PM	2,309	909	2,481	93.1	100	91	111
May 31, 2009	7 AM	755	-90	760	-99.3	33	33	37

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Table 4 lists the capacitors on the two feeders and their status at the minimum and maximum load times shown in Table 3.

Table 4 ***– Status of capacitors***

Capacitor	KVAR Size	Fixed or Switched	Status	
			Min load	Max Load
Hondale 12				
C917D	600	F	ON	ON
C919D	600	F	ON	ON
C1183D	1,800	S	OFF	ON
Hermanas 12				
C920D	600	F	ON	ON
C1181D	1,800	S	OFF	OFF

The controller on capacitor C1183D was malfunctioning from July 15, 2009 @ 2:14 PM to November 16, 2009 @ 11:03 AM. During this time the capacitor was always energized. The controller has been repaired and is now operating properly. During maximum load periods the capacitor should not be energized. This Study assumes proper operation of the capacitor.

The Hondale Feeder 12 minimum load has a very leading power factor due to the low KW demand and the two energized fixed capacitors. This is considered an abnormal operating condition. The analysis in this Study is based on capacitor C917D being de-energized for low load periods.

4.1 Screen for PV system impacts associated with power factor setting

Scenarios reviewed by this Study define an inverter based distributed generation facility operating with a power factor other than unity to be a facility that is absorbing or importing reactive power from the distribution system at the POI. Inverter control systems can be adjusted to allow the PV system to absorb reactive power (Vars) from the distribution system at the POI. Recommendations to absorb reactive power at the POI to mitigate voltage rise impact on the electric distribution system will be evaluated for all operating conditions when reviewing the impact of the Project maintaining voltages within ANSI C84.1 criteria limits.

The electric distribution system was screened to determine if there are any adverse impacts associated with Project Hondale injecting energy into the distribution system at the POI. Project Hondale was evaluated operating at a 100% (unity) power factor to determine if system criteria limits were violated. The system was evaluated with and without Project Hondale for maximum and minimum load during normal and contingency conditions to ensure the distribution system operated within the voltage criteria limits of ANSI C84.1. Operating conditions resulting in voltages outside of the criteria limits will require voltage control utilizing a different power factor setting on the PV project.

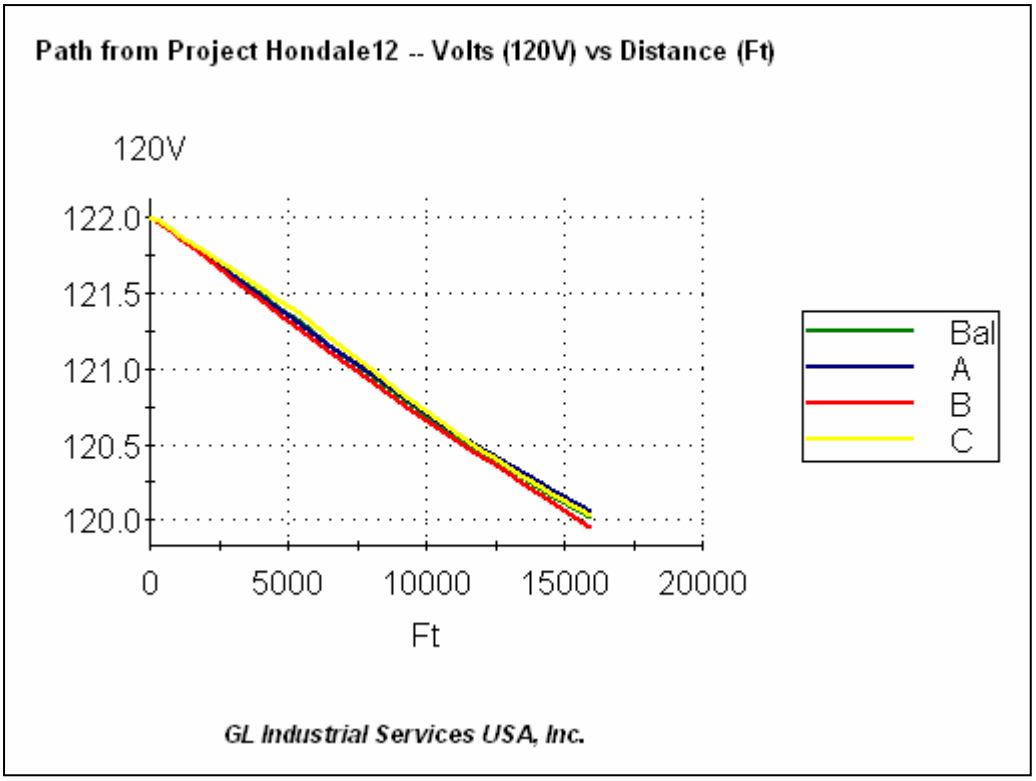
4.2 Voltage impacts on the transmission system

Project Hondale operating at a 100% power factor will be injecting 6,000 KW into the distribution system at the POI. The peak load on Hondale Substation (see Table 2) is approximately the same as the Project rated output. The minimum load on Hondale Substation will be lower than the Project rated output which may result in a flow of power through the substation transformer into the transmission system. No transmission system related issues are anticipated to be associated with Project Hondale at maximum or minimum output.

4.3 Voltage impacts for maximum daylight hours load

The Hondale Feeder 12 voltage for the feeder daylight hours maximum load for 2009 with and without Project Hondale, per the Synergee model, are shown in Graphs 3 and 4.

***Graph 1* - Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale POI for daylight hours maximum load on July 30, 2009. Project Hondale is OFF.**

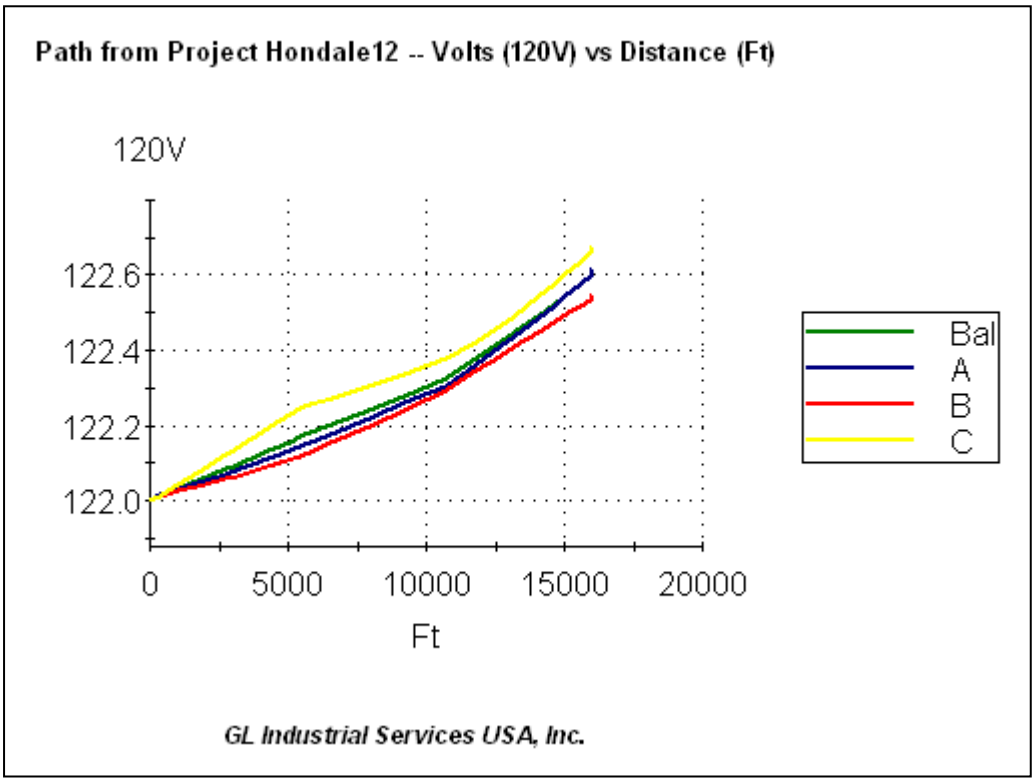


The model voltages at the point of interconnection are:

Phase A – 120.0 volts Phase B – 120.1 volts Phase C – 120.0 volts Balanced – 120.0 volts

The voltages on Hondale Feeder 12 prior to the installation of Project Hondale are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor on Hondale Feeder 12 being de-energized.

<u>Graph 2</u> – Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale POI for daylight hours maximum load on July 30, 2009. Project Hondale is ON at a 100% power factor.



The model voltages at the point of interconnection are:

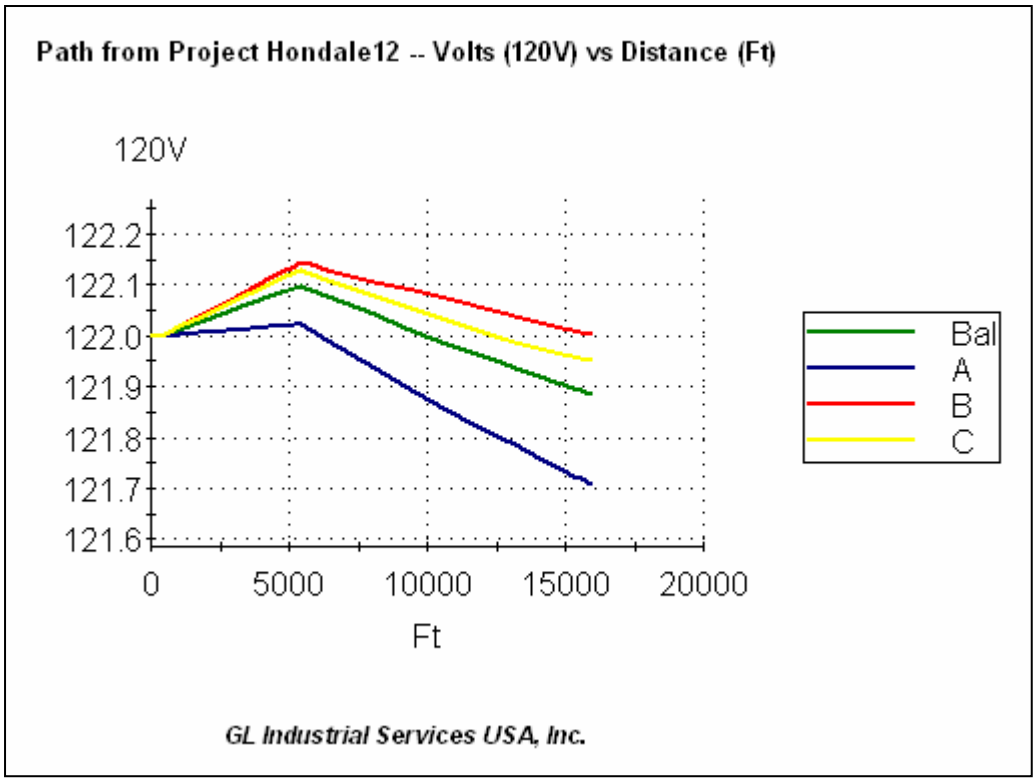
Phase A – 122.6 volts Phase B – 122.5 volts Phase C – 122.7 volts Balanced – 122.6 volts

The voltages on Hondale Feeder 12 after the installation of Project Hondale operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor on Hondale Feeder 12 being de-energized.

4.4 Voltage impacts for minimum daylight hours load

The Hondale Feeder 12 voltage for the feeder daylight hours minimum load for 2009 with and without Project Hondale, per the Synergee model, are shown in Graphs 5 and 6.

<u>Graph 3</u> – Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale POI for daylight hours minimum load on January 15, 2009. Project Hondale is OFF.

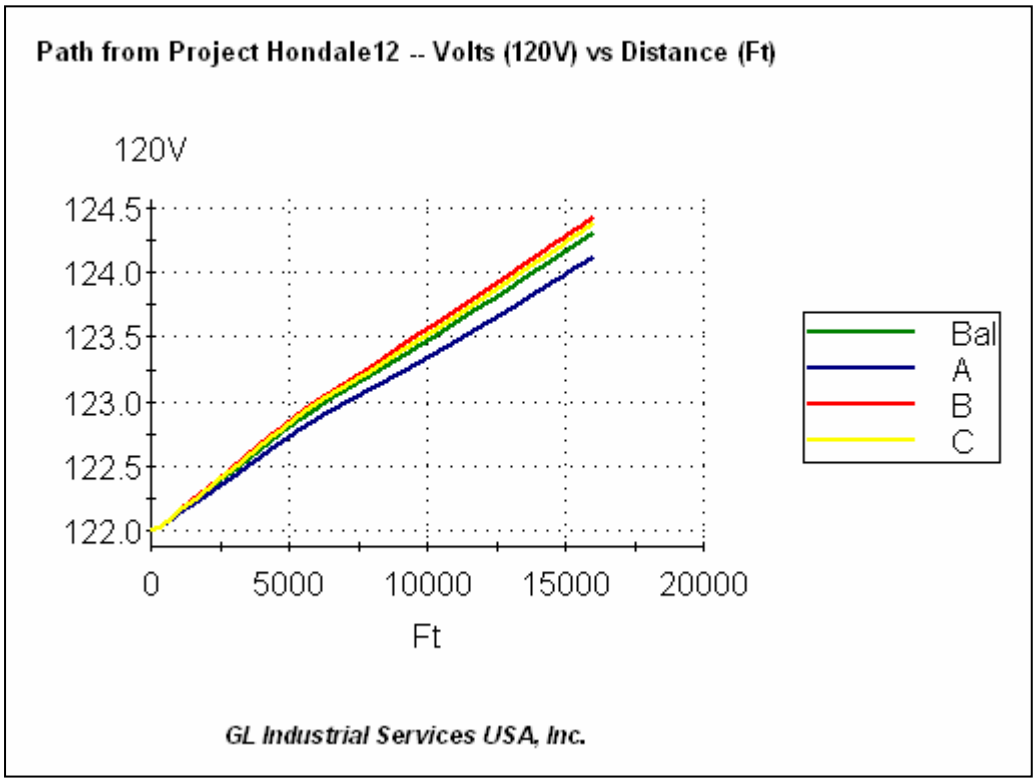


The model voltages at the point of interconnection are:

Phase A – 121.7 volts Phase B – 122.0 volts Phase C – 121.9 volts Balanced – 121.9 volts

The voltages on Hondale Feeder 12 prior to the installation of Project Hondale are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor and one 600 KVAR capacitor on Hondale Feeder 12 being de-energized.

<u>Graph 4</u> - Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale POI for daylight hours minimum load on January 15, 2009. Project Hondale is ON at a 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 124.1 volts Phase B – 124.4 volts Phase C – 124.4 volts Balanced – 124.1 volts

The voltages on Hondale Feeder 12 after the installation of Project Hondale operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor and one 600 KVAR capacitor on Hondale Feeder 12 being de-energized.

In conclusion, Project Hondale operating at a 100% power factor output does cause the voltage on Hondale Feeder 12 at the Project POI to increase but the voltage stays within the PNM criteria of ANSI C84.1.

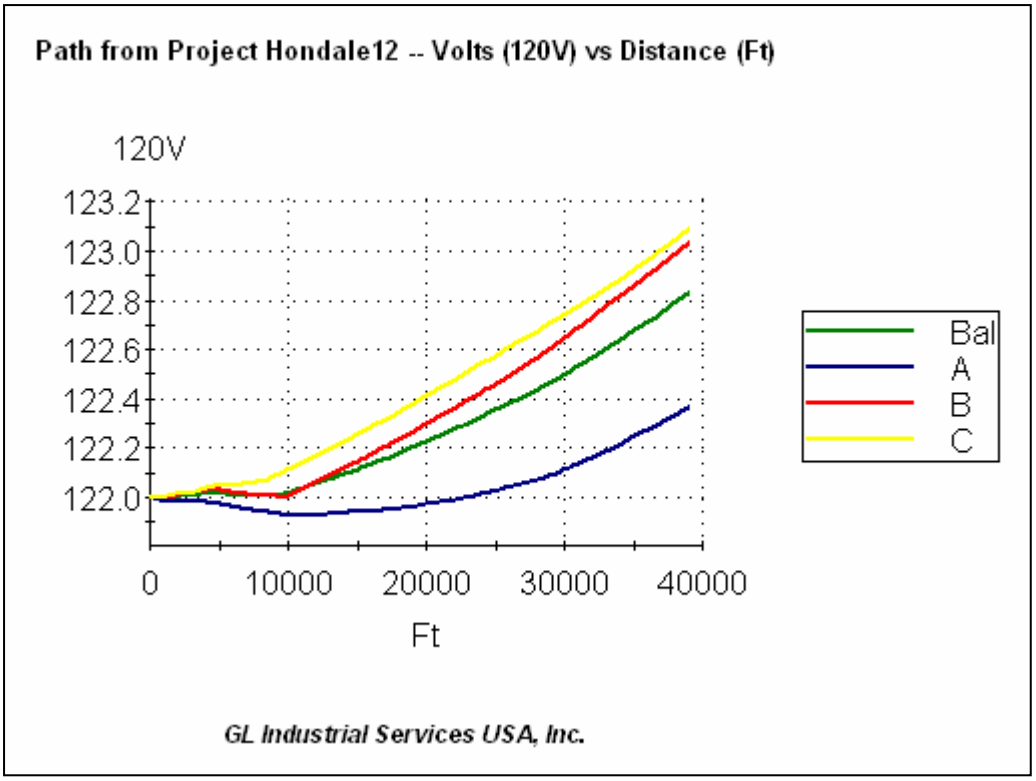
4.5 Voltage impacts during an outage of Hondale Substation

Hermanas Feeder 12 backs up Hondale Feeder 12 when Hondale Substation is out-of-service due to maintenance or equipment failure. The minimum and maximum loading on Hermanas Feeder 12 and Hondale Feeder 12 for the hours of 7AM to 7PM is shown in Table 3. For the condition of Hondale Substation out-of-service, 100% of Hondale Feeder 12 is transferred to Hermanas Feeder 12.

4.5.1 Voltage impacts for daylight hours minimum load during an outage of Hondale Substation

The Hermanas Feeder 12 voltage for daylight hours minimum load for 2009 with and without Project Hondale, per the Synergee model, are shown in Graphs 7, 8 and 9.

<u>Graph 5</u> – Hermanas Feeder 12 voltage drop from Hermanas Substation to Project Hondale POI for daylight hours minimum load. Project Hondale is OFF.

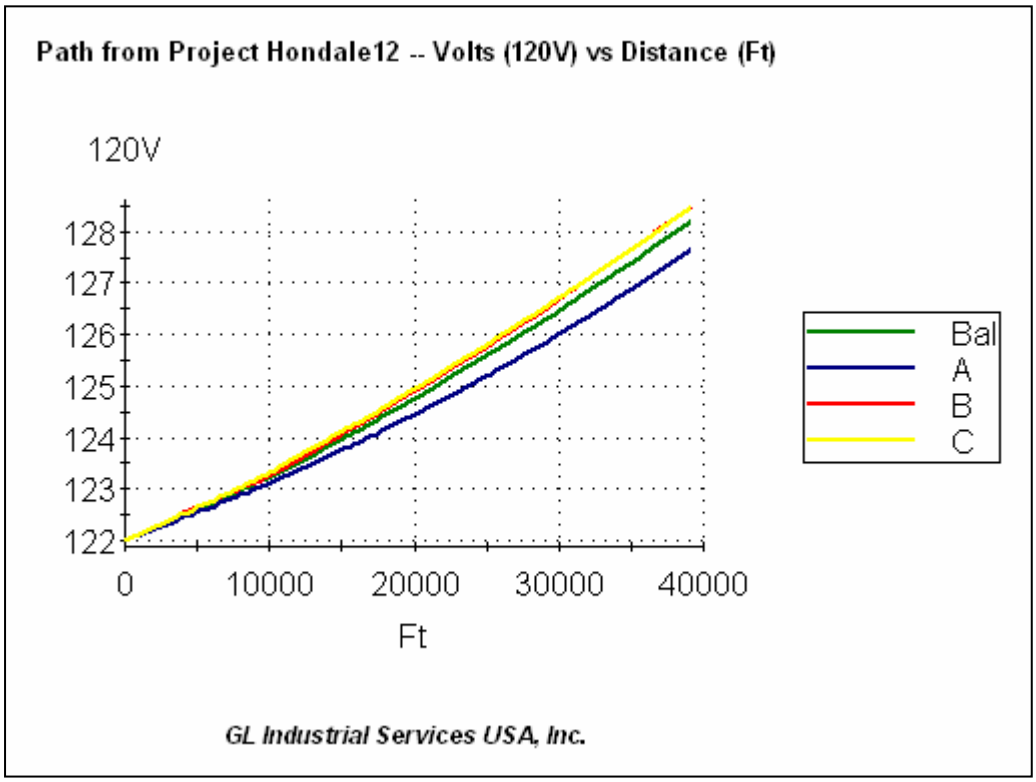


The model voltages at the point of interconnection are:

Phase A – 122.4 volts Phase B – 123.0 volts Phase C – 123.1 volts Balanced – 122.8 volts

The voltages on Hermanas Feeder 12 prior to the installation of Project Hondale are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor and one 600 KVAR capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

Graph 6 ***– Hermanas Feeder 12 voltage drop from Hermanas Substation to Project Hondale POI for daylight hours minimum load. Project Hondale is ON at a 100% power factor.***



The model voltages at the point of interconnection are:

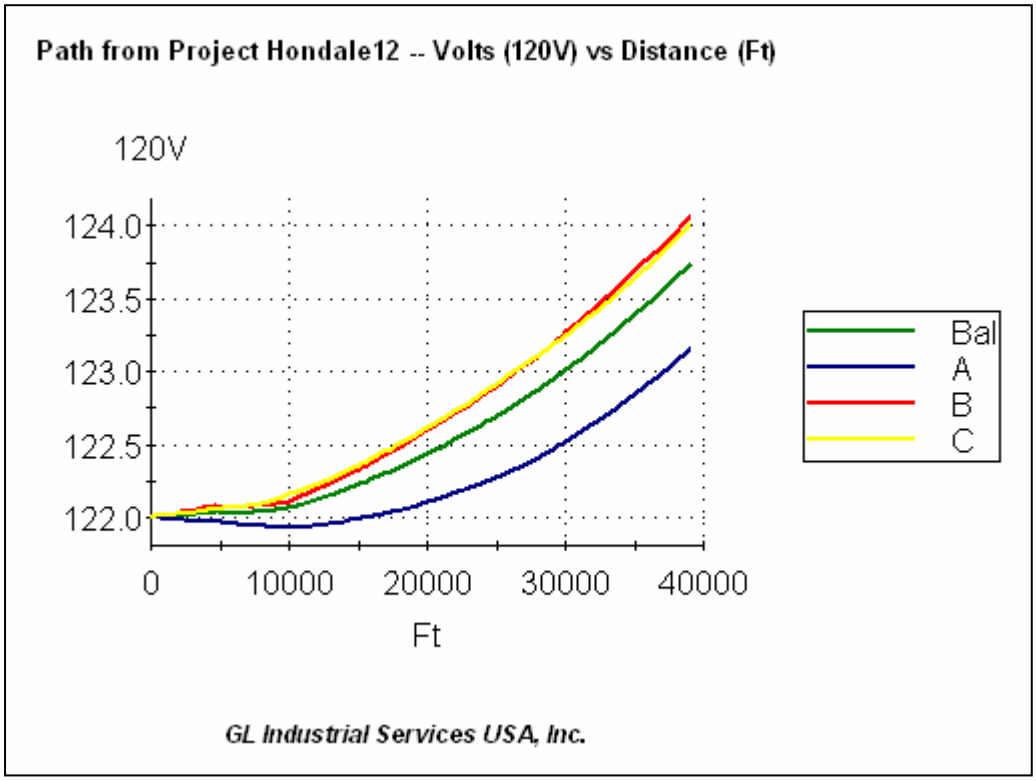
Phase A – 127.7 volts Phase B – 128.5 volts Phase C – 128.5 volts Balanced – 128.2 volts

The voltages on Hermanas Feeder 12 after the installation of Project Hondale operating at a 100% power factor are above the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are unacceptable. This model is based on the 1,800 KVAR switched capacitor and one 600 KVAR capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

Project Hondale has an adverse impact on the PNM electric distribution system for an outage of Hondale Substation with Hondale Feeder 12 transferred to Hermanas Feeder 12 when operating at a 100% (unity) power factor. Voltage control utilizing a different power factor setting on the Project is necessary.

Setting Project Hondale to a 97% power factor such that the Project is injecting 5,820 KW into the distribution system at the POI and absorbing 1,459 KVAR from the distribution system at the POI is required to mitigate voltages above the ANSI C84.1 criteria limits. Graph 9 is the same condition as shown in Graph 8 except Project Hondale is modeled with a 97% power factor

Graph 7 – Hermanas Feeder 12 voltage drop from Hermanas Substation to Project Hondale POI for daylight hours minimum load. Project Hondale is ON at a 97% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.2 volts Phase B – 124.1 volts Phase C – 124.0 volts Balanced – 123.7 volts

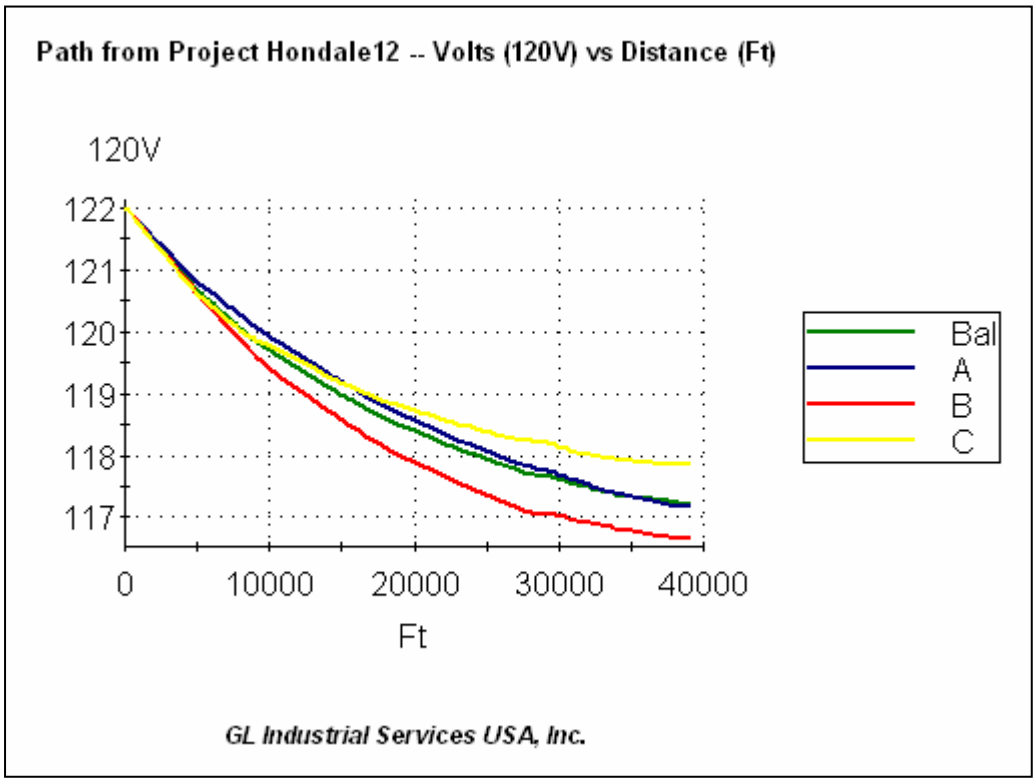
The voltages on Hermanas Feeder 12 after the installation of Project Hondale operating at a 97% power factor are below the PNM voltage criteria (ANSI C84.1) upper limit of 126 volts at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor and one 600 KVAR capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

In conclusion, Project Hondale operating at a 100% (unity) power factor has an adverse impact on the PNM electric distribution system when Hermanas Feeder 12 is supporting Hondale Feeder 12 due to Hondale Substation being out-of-service. Voltages at the Project POI are above the ANSI C84.1 upper limit and are unacceptable. Voltage control utilizing a different power factor setting on the Project is necessary. Setting Project Hondale to a 97% power factor such that the Project is injecting 5,820 KW into the distribution system at the POI and absorbing 1,459 KVAR from the distribution system at the POI is required to mitigate voltages above the ANSI C84.1 criteria limits. Project Hondale operating at a 97% power factor output does cause the voltage on Hermanas Feeder 12 when supporting Hondale Feeder 12 due to Hondale Substation being out-of-service to increase but the voltage stays within the PNM criteria of ANSI C84.1.

4.5.2 Voltage impacts for daylight hours maximum load during an outage of Hondale Substation

The Hermanas Feeder 12 voltage for daylight hours maximum load for 2009 with and without Project Hondale, per the Synergee model, are shown in Graphs 10 and 11.

***Graph 8* – Hermanas Feeder 12 voltage drop from Hermanas Substation to Project Hondale POI for daylight hours maximum load. Project Hondale is OFF.**

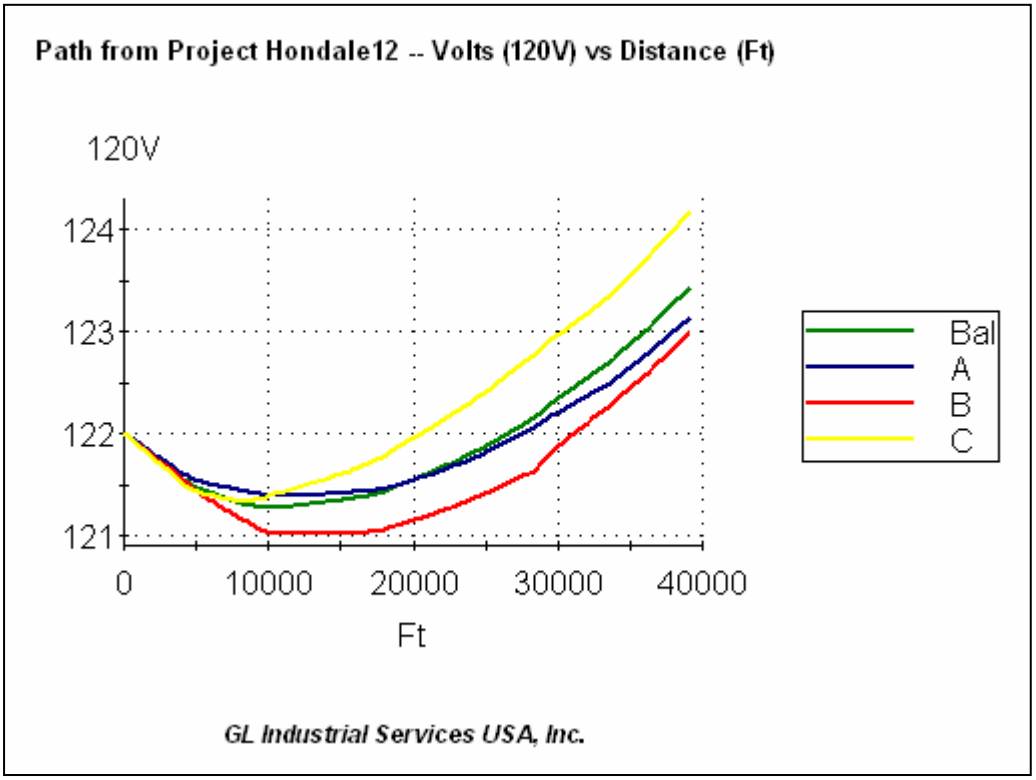


The model voltages at the point of interconnection are:

Phase A – 117.2 volts Phase B – 116.6 volts Phase C – 117.9 volts Balanced – 117.2 volts

The voltages on Hermanas Feeder 12 prior to the installation of Project Hondale are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

***Graph 9* – Hermanas Feeder 12 voltage drop from Hermanas Substation to Project Hondale POI for daylight hours maximum load. Project Hondale is ON at a 100% power factor.**



The model voltages at the point of interconnection are:

Phase A – 123.1 volts Phase B – 123.0 volts Phase C – 124.3 volts Balanced – 123.4 volts

The voltages on Hermanas Feeder 12 after the installation of Project Hondale operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on the 1,800 KVAR switched capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

In conclusion, Project Hondale operating at a 100% power factor output does cause the voltage on Hermanas Feeder 12 when supporting Hondale Feeder 12 due to Hondale Substation being out-of-service to increase but the voltage stays within the PNM criteria of ANSI C84.1.

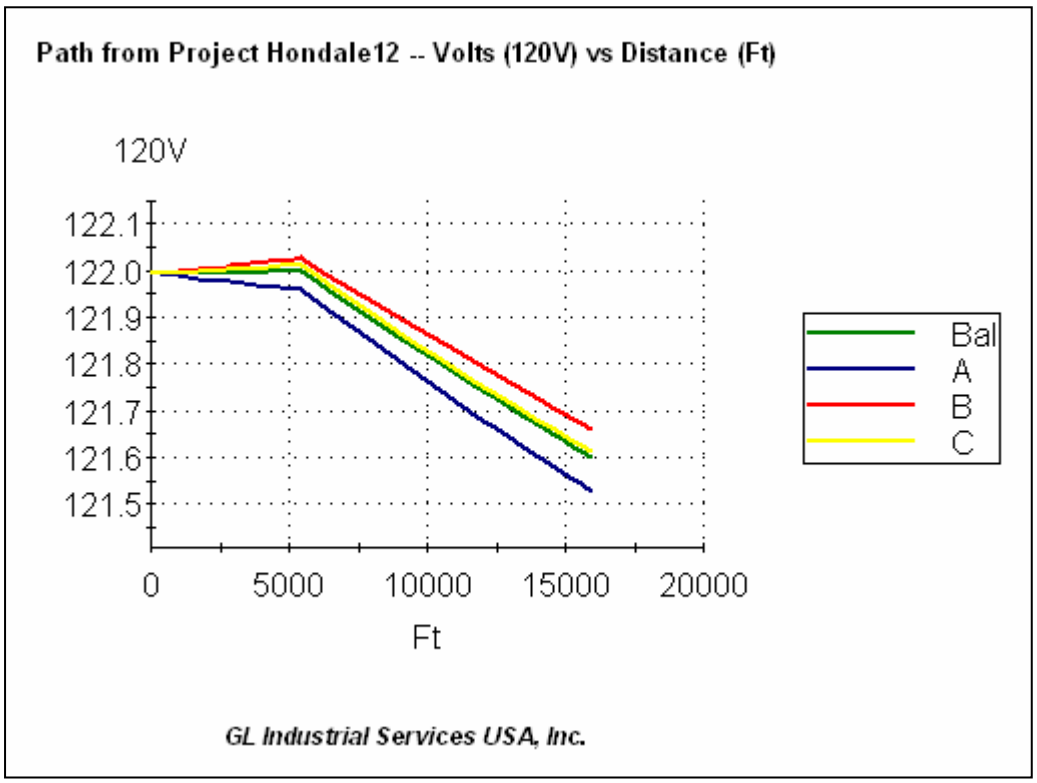
4.6 Voltage impacts during an outage of Hermanas Substation

Hondale Feeder 12 backs up Hermanas Feeder 12 when Hermanas Substation is out-of-service due to maintenance or equipment failure. The minimum and maximum loading on Hondale Feeder 12 and Hermanas Feeder 12 for the hours of 7AM to 7PM is shown in Table 3. For the condition of Hermanas Substation out-of-service, 100% of Hermanas Feeder 12 is transferred to Hondale Feeder 12.

4.6.1 Voltage impacts for daylight hours minimum load during an outage of Hermanas Substation

The Hondale Feeder 12 voltage for daylight hours minimum load for 2009 with and without Project Hondale, per the Synergee model, are shown in Graphs 11 and 12.

***Graph 10* – Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale POI for daylight hours minimum load for a Hermanas Substation outage. Project Hondale is OFF.**

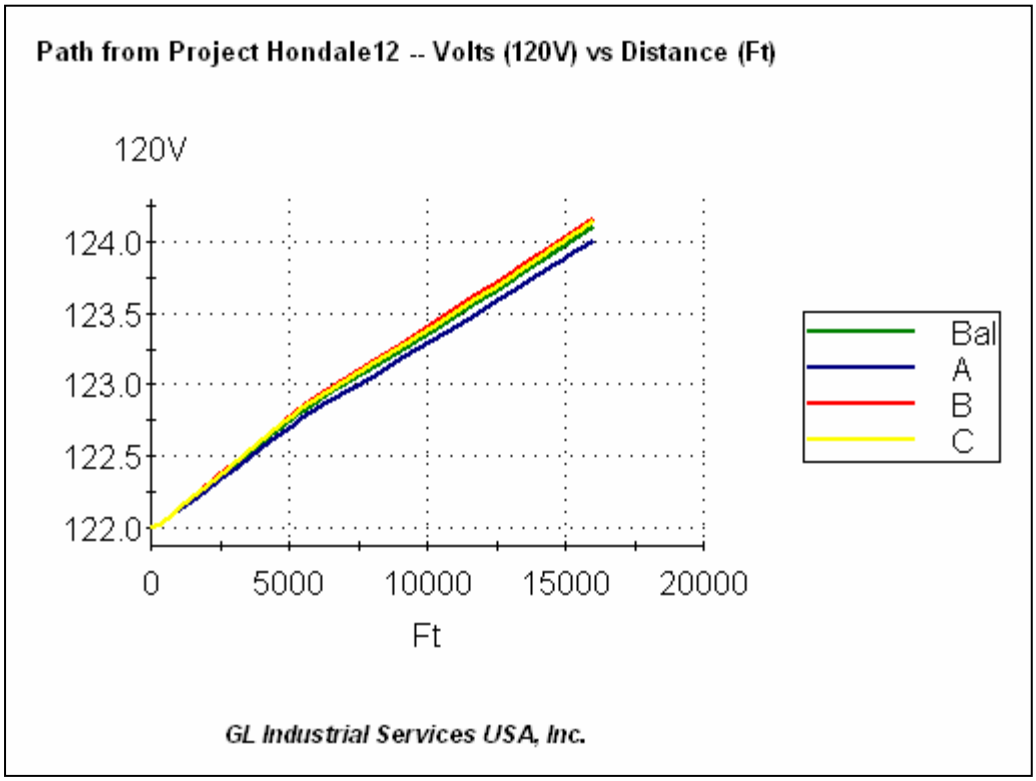


The model voltages at the point of interconnection are:

Phase A – 121.5 volts Phase B – 121.7 volts Phase C – 121.6 volts Balanced – 121.6 volts

The voltages on Hondale Feeder 12 from Hondale Substation to Project Hondale POI during an outage of Hermanas Substation prior to the installation of Project Hondale stay within the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on the 1,800 KVAR switched capacitor and one 600 KVAR capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

***Graph 11* – Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale for daylight hours minimum load for an outage of Hermanas Substation. Project Hondale is ON at a 100% power factor.**



The model voltages at the point of interconnection are:

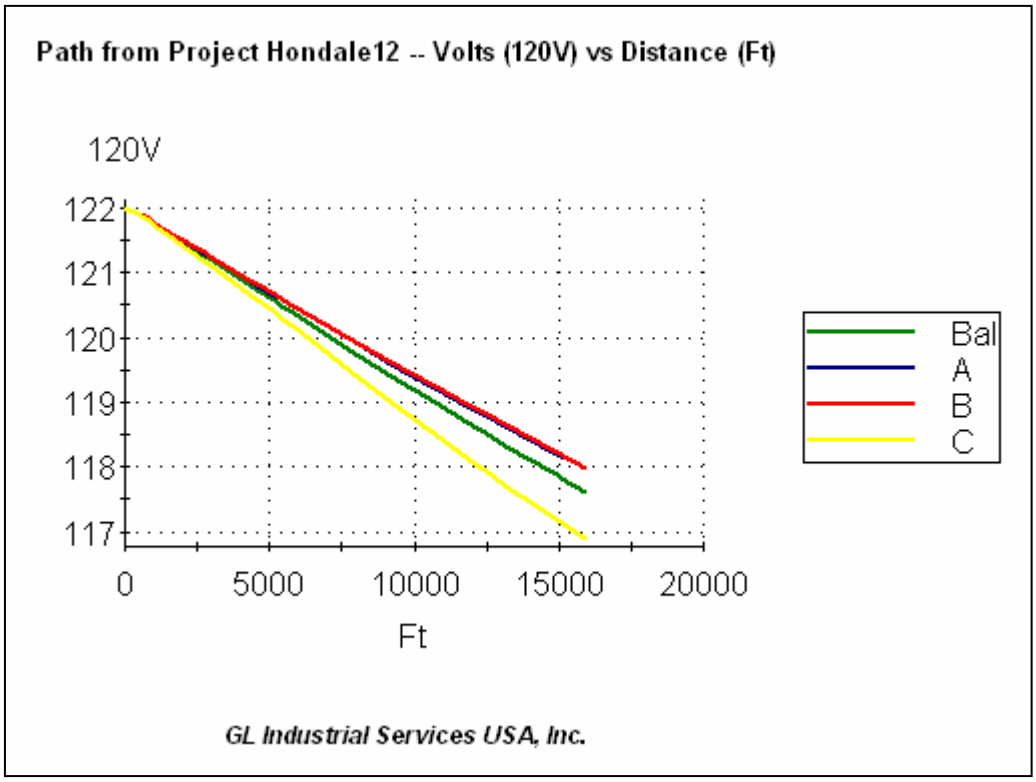
Phase A – 124.0 volts Phase B – 124.2 volts Phase C – 124.0 volts Balanced – 124.1 volts

The voltages on Hondale Feeder 12 from Hondale Substation Project Hondale POI during an outage of Hermanas Substation after the installation of Project Hondale operating at a 100% power factor increase but stay within the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on the 1,800 KVAR switched capacitor and one 600 KVAR capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

4.6.2 Voltage impacts for daylight hours maximum load during an outage of Hermanas Substation

The Hondale Feeder 12 voltage for daylight hours maximum load for 2009 with and without Project Hondale, per the Synergee model, are shown in Graphs 13 and 14.

***Graph 12* – Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale for daylight hours maximum load for an outage of Hermanas Substation. Project Hondale is OFF.**

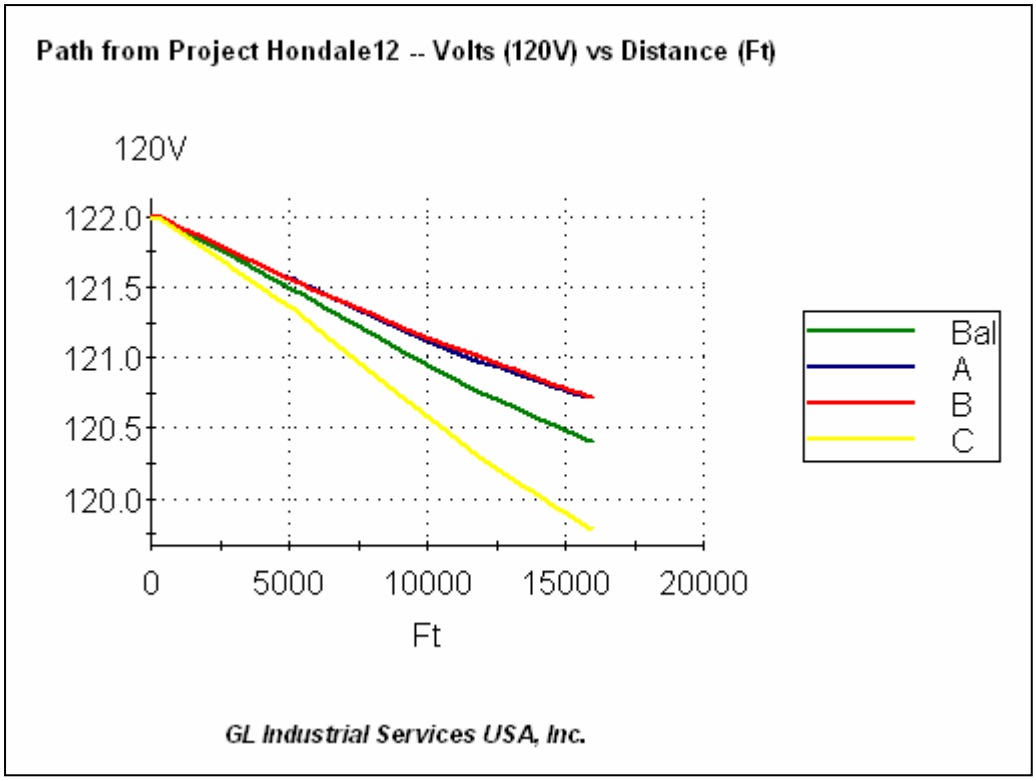


The model voltages at the point of interconnection are:

Phase A – 118.0 volts Phase B – 118.0 volts Phase C – 116.9 volts Balanced – 117.6 volts

The voltages on Hondale Feeder 12 from Hondale Substation to Project Hondale POI during an outage of Hermanas Substation prior to the installation of Project Hondale are above the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on the 1,800 KVAR switched capacitor bank on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

Graph 13 – Hondale Feeder 12 voltage drop from Hondale Substation to Project Hondale for daylight hours maximum load for an outage of Hermanas Substation. Project Hondale is ON at 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 120.7 volts Phase B – 120.7 volts Phase C – 119.8 volts Balanced – 120.4 volts

The voltages on Hondale Feeder 12 from Hondale Substation to Project Hondale POI during an outage of Hermanas Substation after the installation of Project Hondale operating at 100%

power factor are below the PNM voltage criteria (ANSI C84.1) and are acceptable. This model is based on the 1,800 KVAR switched capacitor on Hondale Feeder 12 and the 1,800 KVAR switched capacitor on Hermanas Feeder 12 being de-energized.

In conclusion, Project Hondale operating at a 100% power factor output does cause the voltage on Hondale Feeder 12 when supporting Hermanas Feeder 12 due to Hermanas Substation being out-of-service to increase but the voltage stays within the PNM criteria of ANSI C84.1.

4.7 Voltage impacts overall conclusions

Project Hondale will be connected to Hondale Feeder 12. The feeder has two 600 KVAR fixed capacitors and one 1,800 KVAR switched capacitor. The switched capacitor was malfunctioning for a period but has been returned to normal service. The capacitor is normally de-energized for minimum and maximum load. The two fixed capacitors cause the low load power factor to be unacceptably leading. Distribution Planning will be recommending one fixed capacitor be converted to a switched capacitor such that it is only energized during high load periods.

During normal conditions Project Hondale maximum output operating at 100% (unity) power factor does cause the voltage on Hondale Feeder 12 to increase for minimum and maximum load periods when compared to the Project not in-service. The voltages at the POI remain within the acceptable limits of PNM voltage criteria ANSI C84.1.

Hondale Feeder 12 is supported by Hermanas Substation Feeder 12 for an outage of Hondale Substation. During minimum load period the voltage at the POI is above the ANSI C84.1 upper limit of 126 volts.

There are two options for mitigating Project Hondale adverse impact on the PNM distribution primary system.

OPTION 1

Operate Project Hondale with a fixed 97% power factor during all system conditions, normal and contingent. Therefore, the Project, at maximum capability, will inject 5,820 KW into the

distribution system at the POI and will absorb 1,459 KVAR from the distribution system at the POI. This will allow the Project to operate during all electric system conditions.

OPTION 2

Establish an operating procedure based on limiting the voltage on the PNM distribution system at the POI. The procedure must identify the maximum acceptable voltage at the POI and how it will be monitored. If the voltage exceeds acceptable limits the Project will need to adjust its power factor within a reasonable timeframe or PNM will disconnect the Project to prevent adverse voltages. The Project will be reconnected either when the power factor has been adjusted or system conditions allow.

Distribution Planning recommends Option 2 – develop and implement an operating procedure. The adverse impact occurs during a planned or unplanned outage of Hondale Substation. The operating procedure must have a process to address and correct adverse voltages whenever they occur, whether during normal and contingent electric system conditions. Additionally, the operating procedure will need to include steps for scheduled maintenance which should have ample time to make adjustments to Project Hondale power factor such that it can continue operating and stay connected to the PNM distribution system during the maintenance period.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Hondale Feeder 12 does not have a voltage regulator installed on the feeder. The substation LTC is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 120.5 volts and will reduce the voltage if the substation bus is above 123.5 volts.

Synergee modeling showed that the voltage variance at the substation due to Project Hondale operating at a 97% power factor injecting 5,820 KW into the distribution feeder at the POI and absorbing 1,459 KVAR from the distribution feeder at the POI would be about 0.6 volts for high

or low load periods. This voltage variance may cause the substation LTC to operate for high or low load on the feeder but this is not an adverse impact.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Hondale POI is shown in Section 4.0. Table 4 summarizes the balanced voltage and the calculated voltage flicker. Table 5 is based on the GE flicker graph.

Table 5 ***- Voltage flicker on Hondale Feeder 12 due to Project Hondale***

	POI Voltage Hondale Feeder 12 Loading	
	Minimum	**Maximum**
Without Project	121.9	120.0
With Project	124.1	122.6
% Voltage Flicker	**1.80**	**2.17**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 6 ***– Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
1.80	3/hour	1/minute
2.17	2/hour	1/minute

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 5 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 6. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Hondale POI to the substation were reviewed using the Synergee feeder model with and without Project Hondale operating at a 97% power factor with the Project injecting 5,820 KW into the distribution system and absorbing 1,459 KVAR from the distribution system.

There were no conductor loading problems from the POI to the substation on Hondale Feeder 12 for the normal system configuration or on Hermanas Feeder 12 for the contingent system configuration with and without Project Hondale during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection is typically a real power source (watts only, no vars) for the distribution system. However, Project Hondale is recommended to operate at a 97% power factor and will be injecting 5,820 KW into the distribution system and absorbing 1,459 KVAR from the distribution system. When the inverter is operating the power factor of the distribution feeder will be affected.

RCCS adjusts the power factor of individual feeders by energizing or de-energizing switched capacitors. Hondale Feeder 12 has one 1,800 KVAR RCCS controlled capacitor bank and as discussed in Section 4.0 the capacitor was malfunctioning at the time load data was recorded. Assuming the capacitor had been operating properly the Summer 2009 peak load on the feeder would have been 3,328 KW + j 684 KVAR or 3,398 KVA at a 97.9% lagging power factor. Project Hondale at a 97% power factor will be injecting 5,820 KW into the distribution system at

the POI and absorbing 1,459 KVAR from the distribution system at the POI would change the apparent feeder loading to -2,492 KW + j 2,143 KVAR or 3,287 KVA at a 75.8% lagging power factor. Note that the feeder will be injecting real power into Hondale Substation and absorbing reactive power from Hondale Substation.

The new power factor on Hondale Feeder 12 exceeds the RCCS program control point. The 1,800 KVAR switched capacitor will be energized by the RCCS program resulting in the apparent feeder loading changing to -2,492 + j 343 or 2,515 KVA at a 99.1% lagging power factor. This new power factor does not exceed the RCCS program control point which implies no other capacitor switching. However, there are no other capacitors available for switching. The 1,800 KVAR capacitor is adjacent to the substation and will not have an adverse impact when energized.

9.0 PROTECTION

9.1 Normal Configuration – Service from Hondale Feeder 12

Hondale Substation Feeder 12 is protected by a 1,200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, HU differential relays. Project Hondale will be connected to the distribution primary system approximately 3.03 miles from Hondale Substation. There are five hydraulic reclosers on Hondale Feeder 12, the closest is 2.09 miles from Project Hondale and the farthest is 4.23 miles from Project Hondale.

Fault analysis was conducted to determine the impact of Project Hondale connection on the feeder protective devices. The Project was modeled in SynerGEE to produce the 2,250 amps of fault current on the 270V distribution system as noted on the interconnection application.

The fault evaluate first considered the impact to the reclosers. The available fault current at each recloser, for faults on the system anywhere on the load-side of the reclosers is high enough to meet the required safety factor to maintain proper coordination and adequate

protection. Project Hondale fault current contribution on fuse coordination was evaluated. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 6 MW PV system. Finally, the feeder breaker relay coordination was evaluated. Fault current contributions from Project Hondale do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Hondale does not require any system protection improvements to be made to the Hondale Substation Feeder 12 under normal configuration.

9.2 Contingency Configuration – Hermanas Feeder 12 picks up Hondale Feeder 12 for an outage of Hondale Substation

Hermanas Substation Feeder 12 is protected by a 1,200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, CA differential relays. Project Hondale will be connected to the distribution primary system approximately 7.41 miles from Hermanas Substation. There are six hydraulic reclosers on Hermanas Feeder 12 after picking up Hondale Feeder 12, the closest is 2.09 miles from Project Hondale and the farthest is 6.55 miles from Project Hondale.

Fault analysis was conducted to determine the impact of Project Hondale connection on the feeder protective devices. The Project was modeled in SynerGEE to produce the 2,250 amps of fault current on the 270V distribution system as noted on the interconnection application.

The evaluation first considered the impact to the reclosers. The available fault current at each recloser, for faults on the system anywhere on the load-side of the reclosers is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of Project Hondale fault current contribution on fuse coordination was evaluated. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of Project Hondale. Finally, the feeder breaker relay coordination was evaluated. Fault current contributions from

Project Hondale do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Hondale does not require any system protection improvements to be made to the Hermanas Substation Feeder 12 under contingency configuration.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Hondale operating at a 97% power factor will be injecting 5,820 KW into the distribution system at the POI and absorbing 1,459 KVAR from the distribution system at the POI. Project Hondale output exceeds the minimum and maximum loading on Hondale Feeder 12. Therefore, the Project will cause power to flow into Hondale Substation. Substation load may be exceeded causing power to flow into the transmission system. No transmission related issues are anticipated.

11.0 METERING and COMMUNICATION

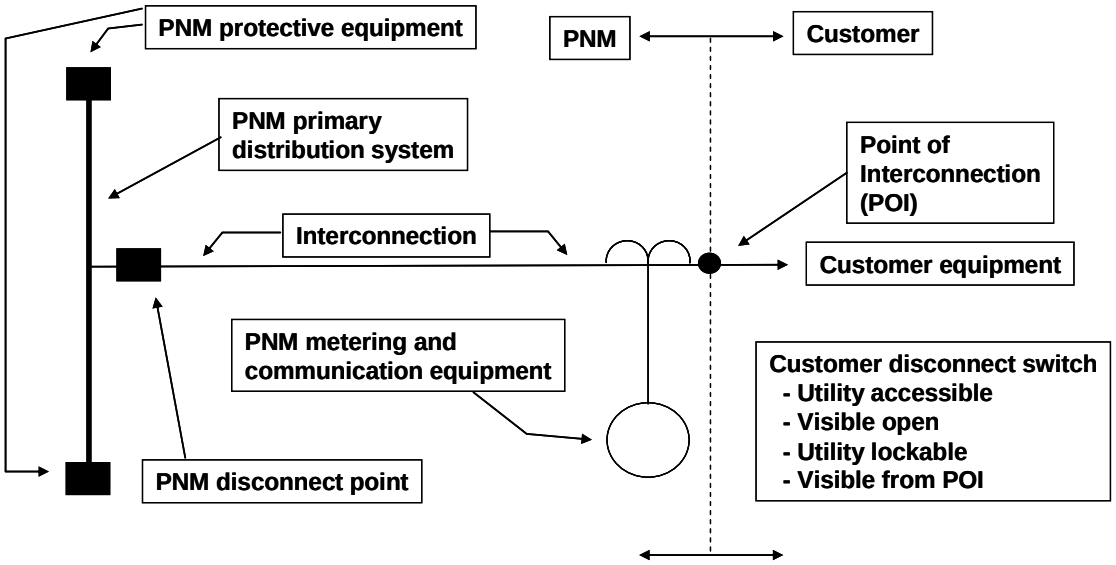
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

***Figure 3** – Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 6.

***Table 7* - Project Hondale Interconnection Cost**

	ESTIMATED COSTS 2010$	ESTIMATED CONSTRUCTION TIME
PNM disconnect point*	$ 48,900	~ 16 week lead time ~ 3 days to build
Interconnection**	$ 18,100	~ 16 week lead time ~ 2 weeks to build
PNM metering	$ 16,100	~ 3 week lead time ~ 4 days to build
Right of Way	$ 2,600	
Protection***	$ 0	
Communication	$ 45,000	
Communication monthly O&M	$ 3,500	
TOTAL	**$ 135,200** **Plus monthly O&M of $3,500**	**5-6 months for lead time and final build out.**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer

easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Distribution Planning performed a screening analysis of Project Hondale 6 MVA PV system operating at 100% (unity) power factor and determined there was an adverse impact on the PNM electric distribution system. Two options were presented to mitigate the adverse impact. Option 1 is to operate the Project at a fixed 97% power factor allowing the electric distribution system to operate within the PNM established criteria. Option 2 is to establish an operating procedure that addresses the process to mitigate the adverse impact on voltage. This Study recommends Option 2 and the establishment of an operating procedure for Project Hondale.

Analysis shows voltages remain within the PNM criteria of ANSI C84.1 for normal system conditions. Project Hondale has an adverse voltage impact for outage of Hondale Substation. This can be mitigated by establishing an operating procedure to reset the Project power factor when voltages at the POI exceed PNM criteria. Remotely controlled capacitor banks on the feeder will be energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC may cause the LTC to operate but this is not considered an adverse issue. The Project output may cause a flow of electricity from the distribution system through the substation transformer, but there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductor ratings to be exceeded. The Project contribution to fault current does not adversely impact the protection coordination on Hondale Feeder 12, Hondale Substation, Hermanas Feeder 12 or Hermanas Substation. Finally, analysis shows that Project Hondale output variation will not cause voltage flicker issues on the electric distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Hondale and has determined that there are no adverse impacts associated with a 6,000 KVA source operating at 100% (unity) power factor during normal conditions. Project Hondale operating at a 100% (unity) power factor has an adverse impact on the PNM electric distribution system when Hermanas Feeder 12 is supporting Hondale Feeder 12 due to Hondale Substation

being out-or-service. Voltage control utilizing a different power setting can mitigate this adverse impact. Establishment of an operating procedure is required to address this adverse impact.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Hondale Substation is maintained within established PNM voltage, equipment and fault protection criteria. Distribution Planning recommends that an operating procedure be developed and implemented to address identified adverse voltage impacts.

XXX

Project Sandia D 5,000 KVA PV Generation Project

Small Generator Interconnection System Impact Study

(SGI-PNM-2010-14)

June 2011

Prepared by:

Public Service Company of New Mexico Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

This report was prepared for XXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts Department.

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EXECUTIVE SUMMARY

XXX submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system with a nominal rating of 5,000 KVA AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Sandia D and would be connected to Innovation Feeder 12. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW. The Interconnection System Impact Study was performed by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts (Distribution Planning).

The estimated cost of connecting Project Sandia D to the distribution primary is:

	ESTIMATED COSTS 2011$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point (Intellirupter)	$ 54,500	~ 26 week lead time ~ 2 Days to build
Interconnection (Line Construction)	$ 54,000	~ 1 week lead time ~ 6 Days to build
PNM Primary metering	$ 18,500	~ 16 week lead time ~ 4 days to build
Communications	$ 45,000	~16 week lead time ~3 weeks to build
TOTAL	**$ 172,000**	**6-7 months for lead time and final build out.**

The technical data notes for the Satcon Powergate Plus 500 kW inverter were used to prepare this report and that this inverter is UL 1741 compliant.

This System Impact Study (Study) evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will

produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Sandia D does not have an adverse impact on the PNM distribution system for normal or contingency conditions.

The Project location will result in an interconnection with Innovation Feeder 12 and the analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds are not anticipated to cause voltage flicker problems.
4. Project output did not cause conductor ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not require the Innovation Feeder 12, Innovation Substation, Four Hills Feeder 12, Four Hills Feeder 14 or Four Hills Substation, protection scheme be modified.
7. Project output will cause a flow of electricity from the distribution system through the substation transformer, but this is not anticipated to cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Sandia D and has determined that there are no adverse impacts associated with a 5,000 KVA AC source connected to Innovation Substation when connected to Innovation Feeder 12.

Distribution Planning has determined that system upgrades are not required to ensure that electric service to all customers on Innovation Substation is maintained within established PNM voltage, equipment and fault protection criteria.

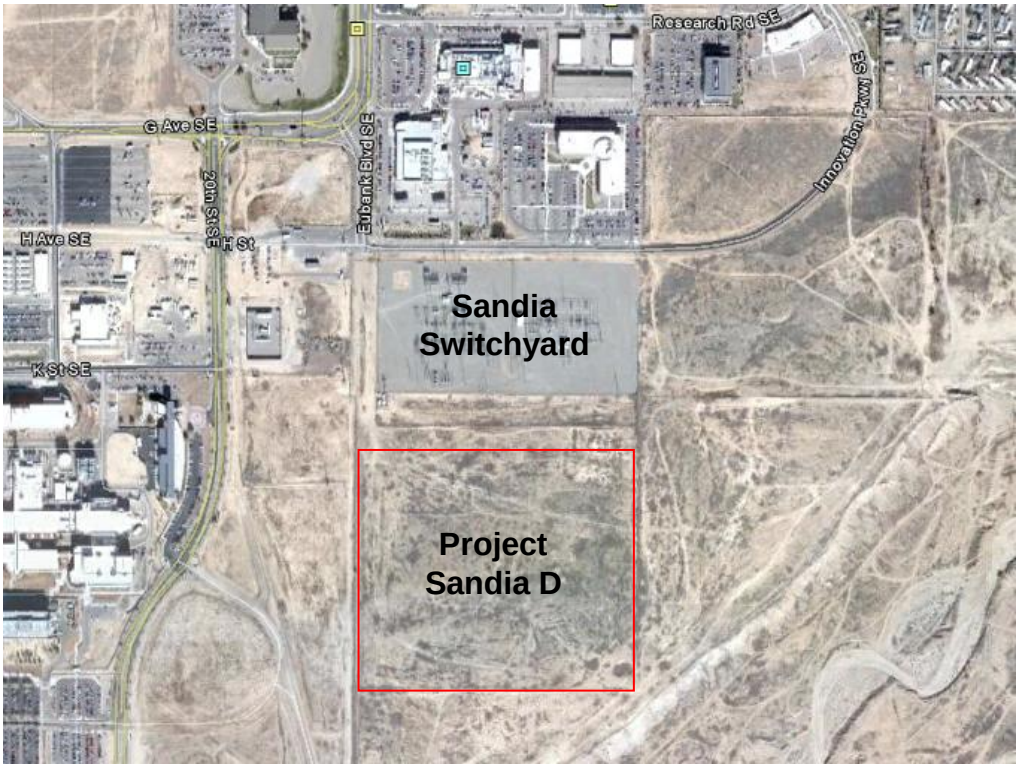
1.0 INTRODUCTION

The purpose of this Study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Sandia D. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Sandia D proposes to connect a 5,000 KVA AC PV facility to Innovation Feeder 12 in the southeast area of Albuquerque, NM. Project Sandia D will be located on the south side of the Sandia Switchyard, south of Innovation Parkway SE as shown in Figure 1. The circuit distance from Innovation Substation to the Project Sandia D point of interconnection (POI) is about 1,900 ft. or 0.36 miles.

***Figure 1* – Project Sandia D Location**



3.0 SYSTEM CONFIGURATION

At the time of this study, the requested point of interconnection is Four Hills Feeder 14 and a new substation is presently being installed at the Sandia Switchyard. The requested In-Service date for the interconnection is Dec. 1, 2011. By this date, the system configuration will be different. The new substation will be online and will be carrying load from the surrounding Lenkurt and Four Hills Feeders. This study assumes the new configuration and that the existing portion of the Four Hills Feeder 14 for interconnection will be Innovation Feeder 12. All loads stated in this study are based on the SynerGEE model which used 2009 loads for the feeders in the present system configuration as the base. In June 2010, PNM evaluated two 1,000 KVA PV installations, one on Lenkurt Feeder 14 (Project DG2) and the other on Four Hills Feeder 14 (Project DG1). The studies for Project DG1 and DG2 concluded that there were no adverse impacts on their respective feeders for normal or contingency configurations. For this study, Projects DG1 and DG2 are assumed to be on, and located on the new Innovation 11 and 12 feeders.

Project Sandia D is a large PV source and is proposed to be connected to Innovation Feeder 12 served from Innovation Substation. Table 1 shows the rating of Innovation Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Innovation	33.6	40.8	43.2	115 -12.47

Table 2 shows the modeled 2009 peak summer loads for Innovation Substation and feeders, based on the SynerGEE model for the new configuration, this data is not coincident with PNM's 2009 system wide peak demand timeframe.

Table 2 ***– Modeled July 2009 Non-coincident Peak Loads***

Feeder	Modeled July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Innovation 11	4,406	2,046	4,858	90.7
Innovation 12	3,759	-156	3,762	-99.9
Innovation 13	2,692	541	2,746	98.0
Innovation Substation	10,857	2,431	11,126	97.6

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours – the first condition is the peak load on each study area distribution circuit and the second condition is the minimum load on each study area distribution circuit. The times for maximum and minimum load are non-coincident for the distribution circuits.

The daylight hours are based on sunrise and sunset time for January through December in the Albuquerque area using 2009 data.

Table 3 shows the daylight hours time (mountain time zone) range for each month for determining the maximum and minimum loading used in a PV system impact study.

Table 3 ***– Time range for PV studies***

Time Range for PV Studies		
7 AM - 7 PM	**8 AM – 5 PM**	**8 AM – 4 PM**
April	March	January
May	September	February
June	October	November
July		December

August		

The modeled maximum and minimum daylight hours loading on the Innovation Feeder 12 are shown in Table 4:

Table 4 ***- Innovation Feeder 12 modeled max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
August 4, 2009	3 PM	3,759	-156	3,762	-99.9	174	176	160
May 30, 2009	7 AM	2,055	929	2,256	91.1	105	104	97

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Sandia D at maximum output exceeds the load on Innovation Feeder 12. Therefore, Project Sandia D will cause a flow of power into Innovation Substation. Table 5 shows the modeled maximum and minimum load on the Innovation Substation transformer.

Table 5 ***- Innovation Substation modeled max/min Daylight Hours Load***

	KW	KVAR	KVA	Power Factor	Phase Amps		
					A	B	C
Maximum	10,857	2,431	11,126	97.6	496	542	503
Minimum	4,388	1088	4,521	97.1	227	235	220

Project Sandia D at maximum output, exceeds the load on the Innovation Substation transformer at minimum load timeframes. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system.

4.1 Voltage impacts on the transmission system

Although the load on the Innovation Substation transformer is less than the rated output of the project for minimum load timeframes, the difference is minimal, therefore no transmission related issues are anticipated to be associated with Project Sandia D.

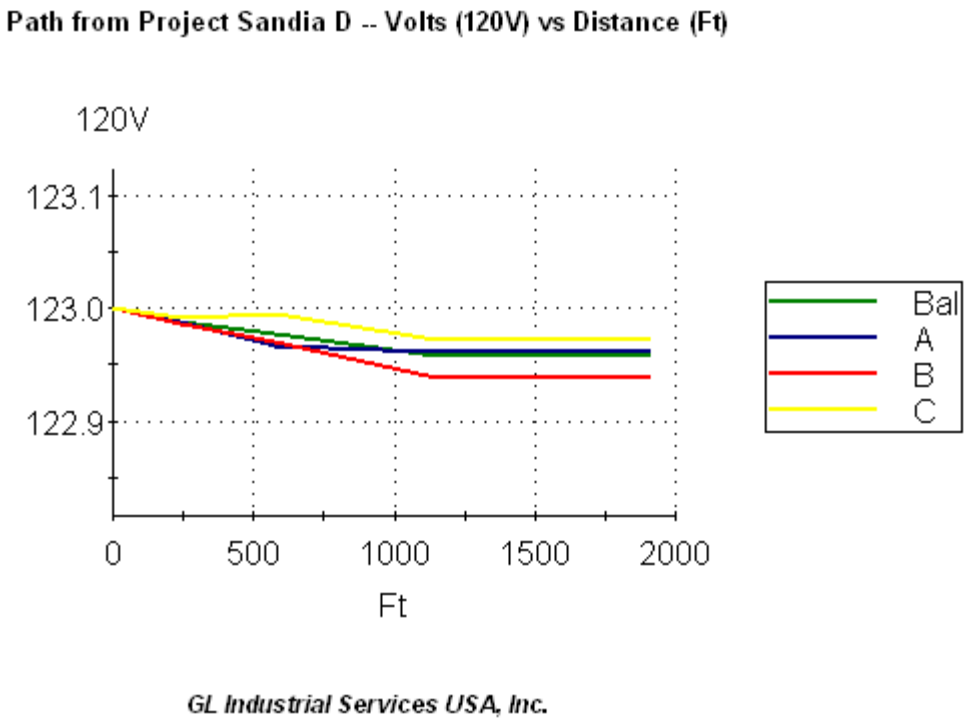
4.2 Screen for PV system impacts associated with power factor setting

The electric distribution system was screened to determine if there are any adverse impacts associated with Project Sandia D injecting energy. Project Sandia D was evaluated operating at a 100% power factor to determine if system criteria limits were violated. The system was evaluated with and without Project Sandia D for maximum and minimum load during normal and contingent conditions. The evaluation with Project Sandia D operating at 100% power factor for maximum load during normal conditions shows that the distribution system voltage is within the ANSI C84.1 criteria and is acceptable.

4.3 Voltage impacts for maximum daylight hours load for normal configuration

The Innovation Feeder 12 voltage for the feeder daylight hours maximum load for 2009 with and without Project Sandia D, per the SynerGEE model, are shown in Graphs 1 and 2. Larger customer loads on the feeder, such as Emcore and Ktech, were modeled using actual load values from the daylight hours maximum date and time. Projects DG1 and DG2 are assumed to be on.

Graph 1 - Innovation Feeder 12 voltage drop from Innovation Substation to Project Sandia D POI for daylight hours maximum load on August 4, 2009. Project Sandia D is OFF.

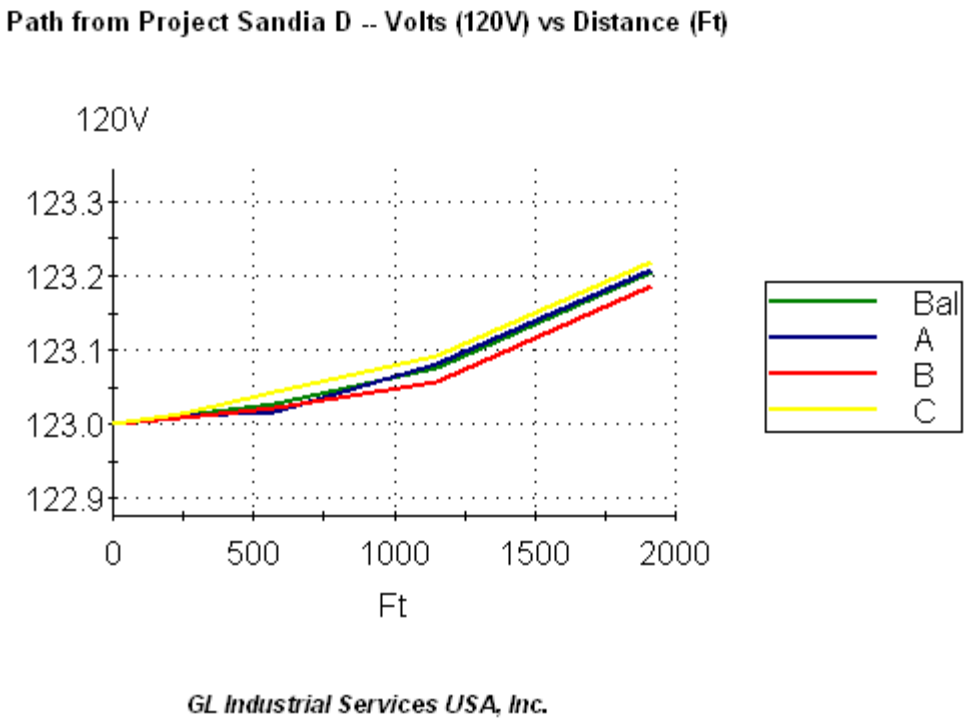


The model voltages at the point of interconnection are:

Phase A – 123.0 volts Phase B – 122.9 volts Phase C – 123.0 volts Balanced – 123.0 volts

The voltages on Innovation Feeder 12 prior to the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 - Innovation Feeder 12 voltage drop from Innovation Substation to Project Sandia D POI for daylight hours maximum load on August 4, 2009. Project Sandia D is ON, 100% power factor.



The model voltages at the point of interconnection are:

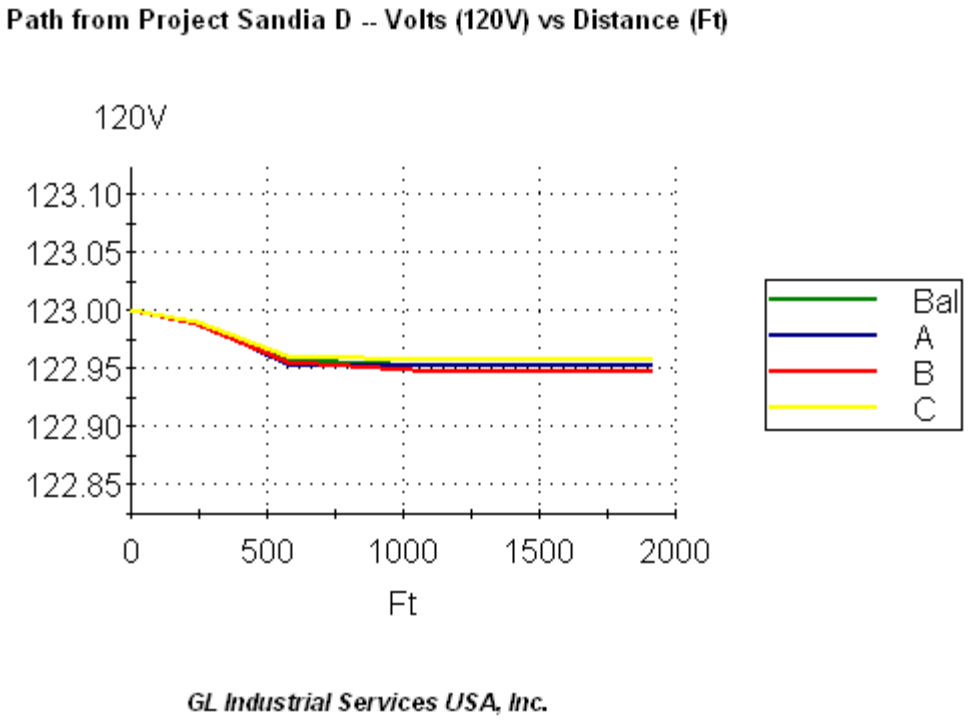
Phase A – 123.2 volts Phase B – 123.2 volts Phase C – 123.2 volts Balanced – 123.2 volts

The voltages on Innovation Feeder 12 after the installation of Project Sandia D are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4 Voltage impacts for minimum daylight hours load for normal configuration

The Innovation Feeder 12 voltage for the feeder daylight hours minimum load for 2009 with and without Project Sandia D, per the SynerGEE model, are shown in Graphs 3 and 4. Larger customer loads on the feeder, such as Emcore and Ktech, were modeled using actual load values from the daylight hours minimum date and time. Projects DG1 and DG2 are assumed to be on.

Graph 3 - Innovation Feeder 12 voltage drop from Innovation Substation to the Project Sandia D POI for daylight hours minimum load on May 30, 2009. Project Sandia D is OFF.

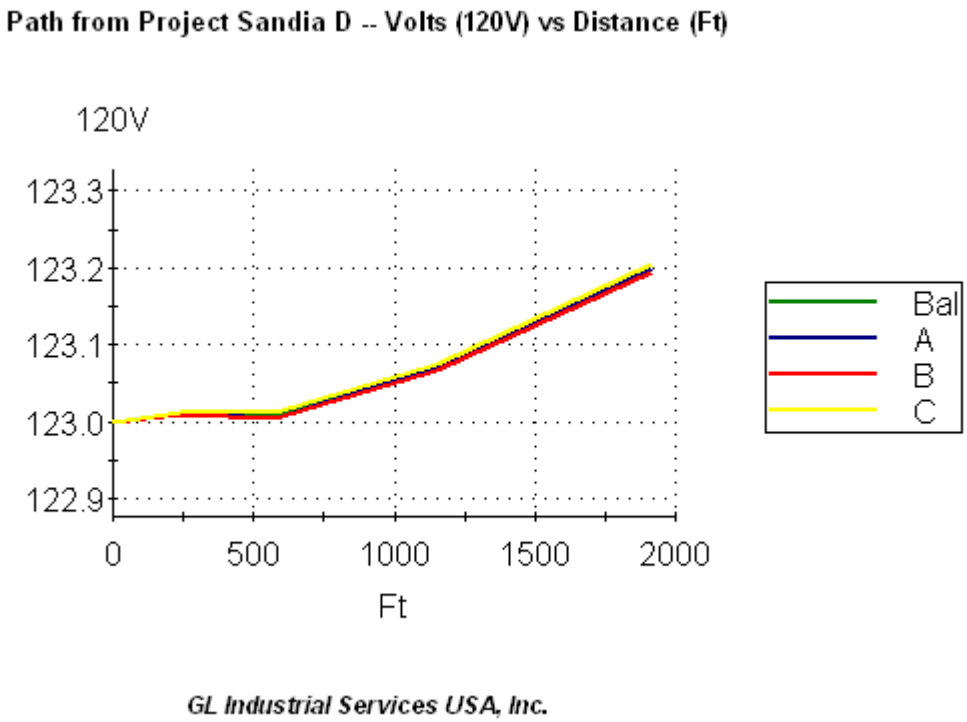


The model voltages at the point of interconnection are:

Phase A – 123.0 volts Phase B – 122.9 volts Phase C – 123.0 volts Balanced – 123.0 Volts.

The voltages on Innovation Feeder 12 prior to the installation of Project Sandia D are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 - Innovation Feeder 12 voltage drop from Innovation Substation to the Project Sandia D POI for daylight hours minimum load on May 30, 2009. Project Sandia D is ON, 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.2 volts Phase B – 123.2 volts Phase C – 123.2 volts Balanced – 123.2 volts.

The voltages on Innovation Feeder 12 after the installation of Project Sandia D are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5 Voltage impacts for maximum daylight hours load for contingency configuration

Presently, there are two possible scenarios for contingency configuration that Project Sandia D can contribute to. The first is for the loss of Innovation Substation, the second is for the loss of Four Hills Substation.

Table 6 shows the load data used for the contingency evaluations. Table 6 shows the 2009 modeled maximum and minimum daylight hours loading on Four Hills Feeder 14.

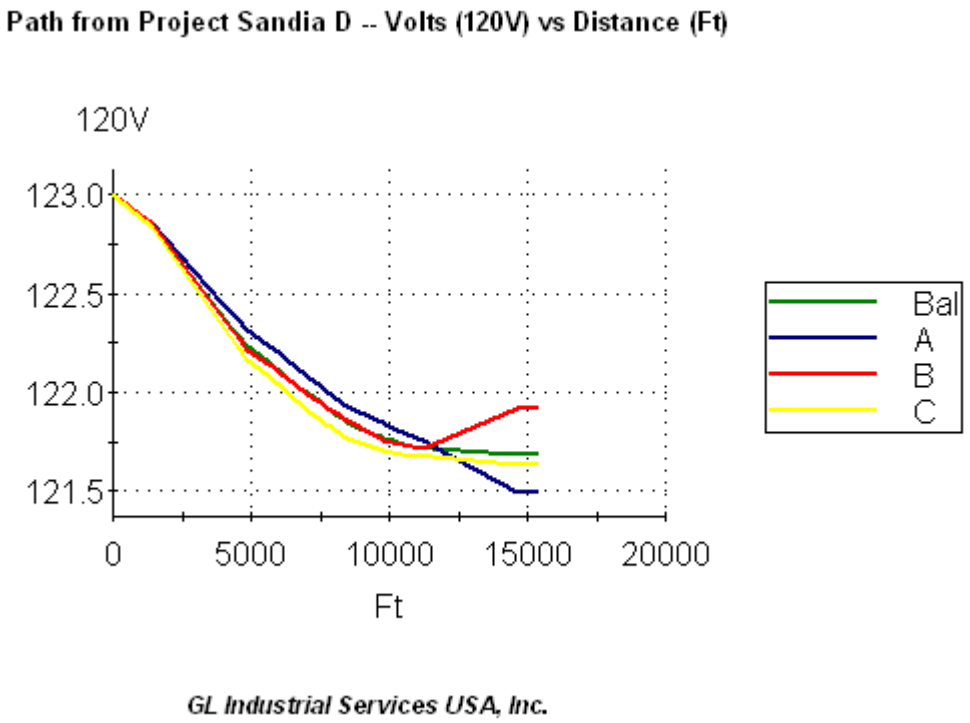
Table 6 ***– Four Hills Feeder 14 modeled max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Aug. 4, 2009	3 PM	1,280	549	1,393	91.9	55	51	83
May 30, 2009	7 AM	333	110	350	95.1	15	13	20

4.5.1 Contingency configuration – Loss of Innovation Substation, maximum load

For the loss of the Innovation Substation, 100% of Innovation Feeder 12 is transferred to Four Hills Substation through 100% of Four Hills Feeder 14. Voltage for the feeder daylight hours maximum load for 2009 with and without Project Sandia D, per the SynerGEE model, are shown in Graphs 5 and 6. Larger customer loads on the feeder, such as Emcore and Ktech, were modeled using actual load values from the daylight hours maximum date and time. Projects DG1 and DG2 are assumed to be on. The circuit distance from Four Hills Substation to the Project Sandia D point of interconnection (POI) is about 15,394 ft. or 2.92 miles.

Graph 5 – Four Hills Feeder 14 voltage drop from Four Hills Substation to the Project Sandia D POI for the loss of Innovation Substation for daylight hours maximum load on August 4, 2009. Project Sandia D is OFF.

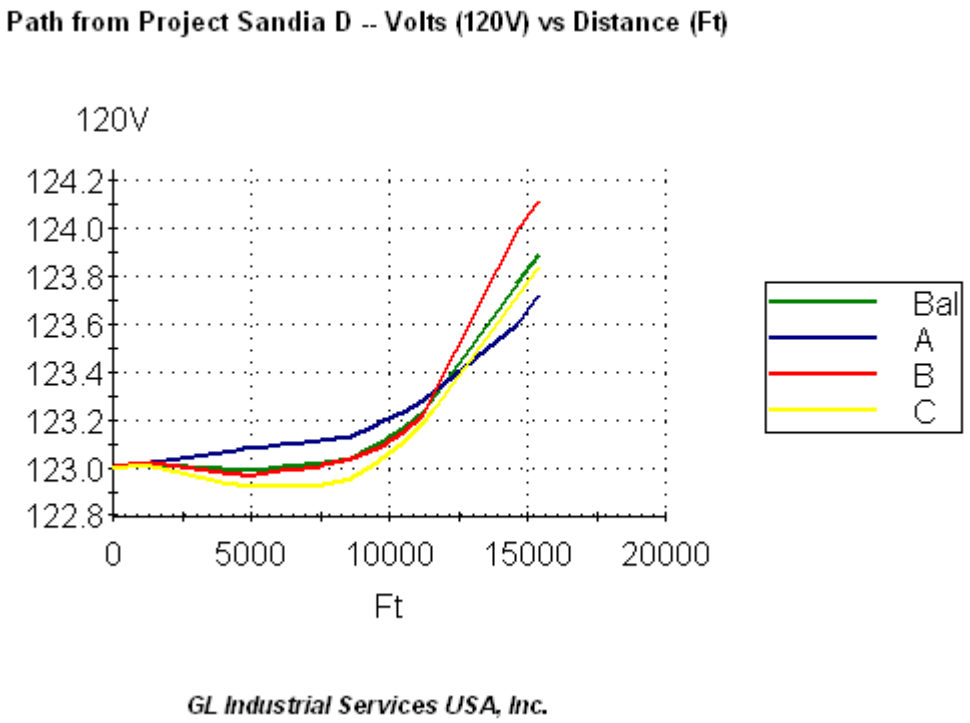


The model voltages at the point of interconnection are:

Phase A – 121.5 volts Phase B – 121.9 volts Phase C – 121.6 volts Balanced – 121.7 volts

The voltages on Four Hills Feeder 14 for the loss of Innovation Substation contingency prior to the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 6 – Four Hills Feeder 14 voltage drop from Four Hills Substation to the Project Sandia D POI for the loss of Innovation Substation for daylight hours maximum load on August 4, 2009. Project Sandia D is ON, 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.7 volts Phase B – 124.1volts Phase C – 123.8 volts Balanced – 123.9 volts

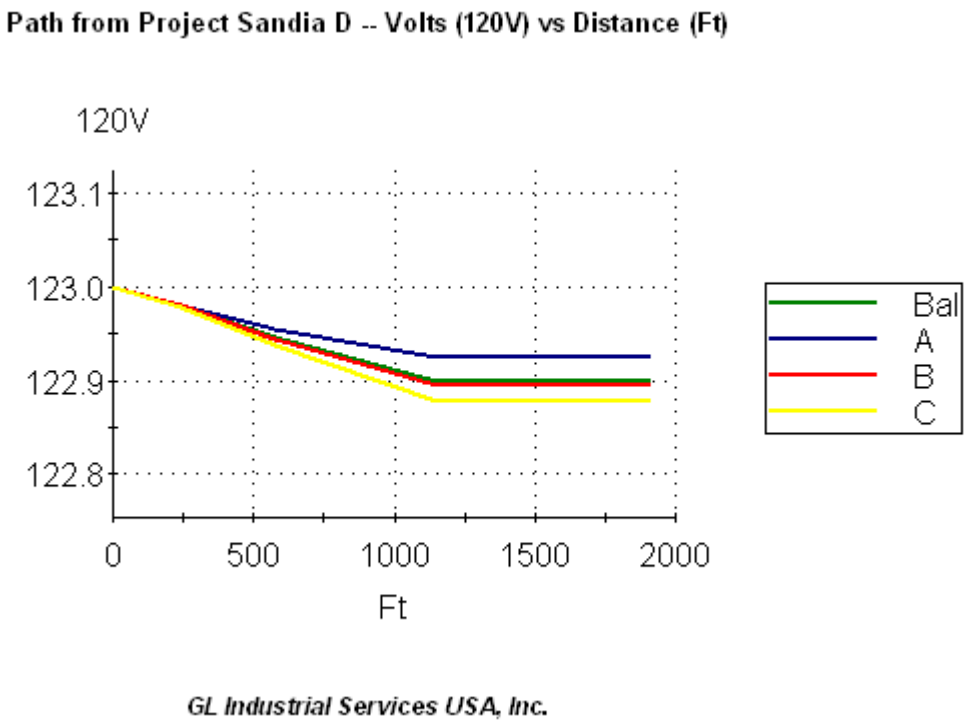
The voltages on Four Hills Feeder 14 for the loss of Innovation Substation contingency after the installation of Project Sandia D are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5.2 Contingency configuration – Loss of Four Hills Substation, maximum load

For the loss of the Four Hills Substation, 100% of Four Hills Feeder 14 is transferred to 100% of Innovation Feeder 12. Voltage for the feeder daylight hours maximum load for 2009 with and without Project Sandia D, per the SynerGEE model, are shown in Graphs 7 and 8. Larger customer loads on the feeder, such as Emcore and Ktech, were modeled using actual load values from the daylight hours maximum date and time. Projects DG1 and DG2 are assumed to

be on. The circuit distance from Innovation Substation to the Project Sandia D POI is the same as was stated earlier for normal configuration.

Graph 7 - Innovation Feeder 12 voltage drop from Innovation Substation to the Project Sandia D POI for the loss of Four Hills Substation for daylight hours maximum load on August 4, 2009. Project Sandia D is OFF.

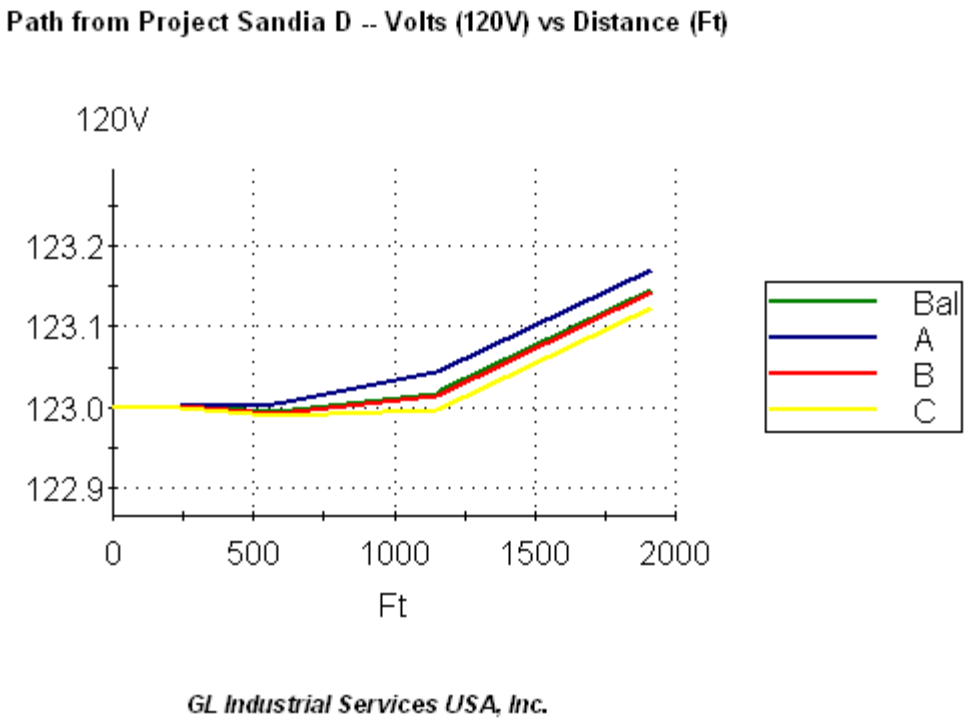


The model voltages at the point of interconnection are:

Phase A – 122.9 volts Phase B – 122.9 volts Phase C – 122.9 volts Balanced – 122.9 volts

The voltages on Innovation Feeder 12 for the loss of Four Hills Substation contingency prior to the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 8 - Innovation Feeder 12 voltage drop from Innovation Substation to the Project Sandia D POI for daylight hours maximum load on August 4, 2009. Project Sandia D is ON, 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.2 volts Phase B – 123.1 volts Phase C – 123.1 volts Balanced – 123.1 volts

The voltages on Innovation Feeder 12 for the loss of Innovation Substation contingency after the installation of Project Sandia D are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

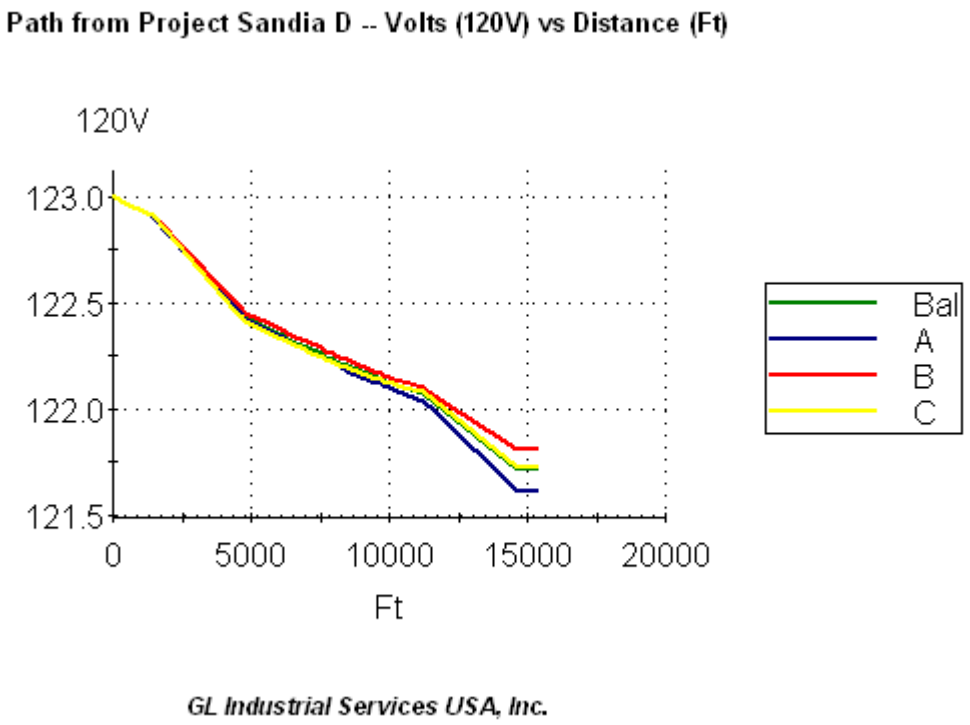
4.6 Voltage impacts for minimum daylight hours load for contingency configuration

4.6.1 Contingency configuration – Loss of Innovation Substation, minimum load

For the loss of the Innovation Substation, 100% of Innovation Feeder 12 is transferred to Four Hills Substation through 100% of Four Hills Feeder 14. Voltage for the feeder daylight hours minimum load for 2009 with and without Project Sandia D, per the SynerGEE model, are shown

in Graphs 9 and 10. Larger customer loads on the feeder were modeled using actual load values from the daylight hours minimum date and time and Projects DG1 and DG2 are assumed to be on.

Graph 9 – Four Hills Feeder 14 voltage drop from Four Hills Substation to the Project Sandia D POI for the loss of Innovation Substation for daylight hours minimum load on May 30, 2009. Project Sandia D is OFF.

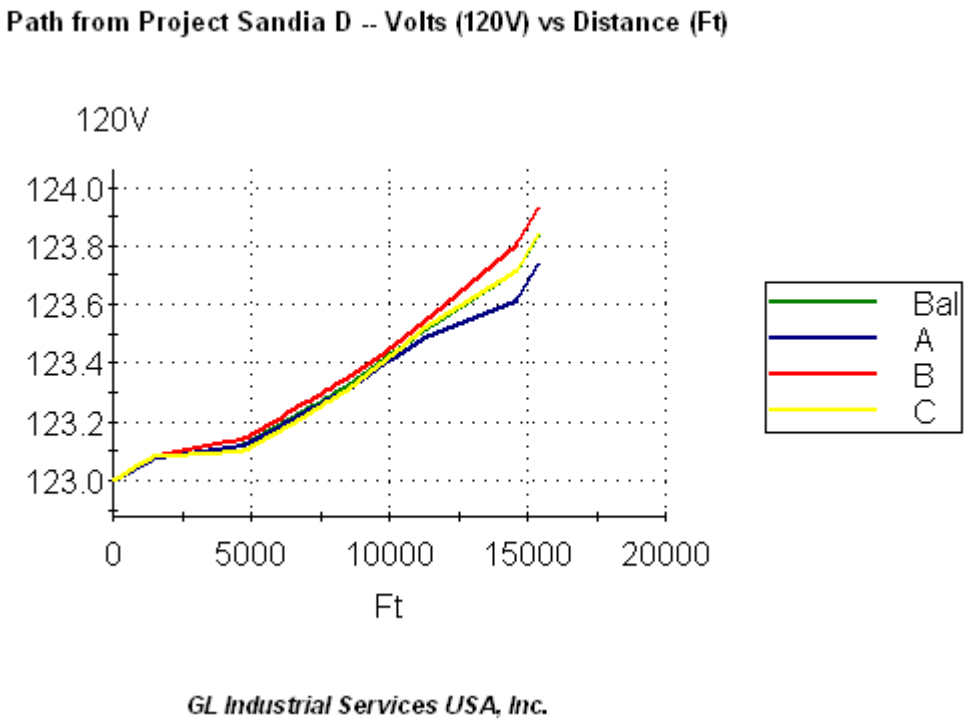


The model voltages at the point of interconnection are:

Phase A – 121.6 volts Phase B – 121.8 volts Phase C – 121.7 volts Balanced – 121.7 volts.

The voltages on Four Hills Feeder 14 for the loss of Innovation Substation contingency prior to the installation of Project Sandia D are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 10 – Four Hills Feeder 14 voltage drop from Four Hills Substation to the Project Sandia D POI for the loss of Innovation Substation for daylight hours minimum load on May 30, 2009. Project Sandia D is ON, 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.7 volts Phase B – 123.9 volts Phase C – 123.8 volts Balanced – 123.8 volts

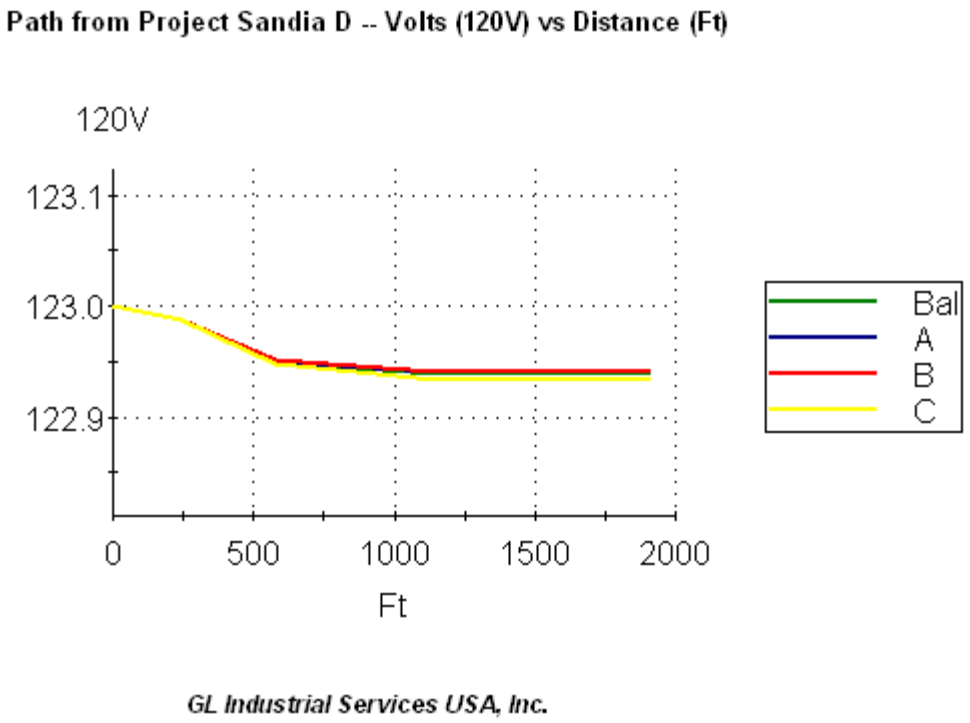
The voltages on Four Hills Feeder 14 for the loss of Innovation Substation contingency after the installation of Project Sandia D are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.6.2 Contingency configuration – Loss of Four Hills Substation, minimum load

For the loss of the Four Hills Substation, 100% of Four Hills Feeder 14 is transferred to 100% of Innovation Feeder 12. Voltage for the feeder daylight hours minimum load for 2009 with and without Project Sandia D, per the SynerGEE model, are shown in Graphs 11 and 12. Larger customer loads on the feeder were modeled using actual load values from the daylight hours minimum date and time and Projects DG1 and DG2 are assumed to be on. The circuit distance

from Innovation Substation to the Project Sandia D POI is the same as was stated earlier for normal configuration.

Graph 11 - Innovation Feeder 12 voltage drop from Innovation Substation to the Project Sandia D POI for the loss of Four Hills Substation for daylight hours minimum load on May 30, 2009. Project Sandia D is OFF.

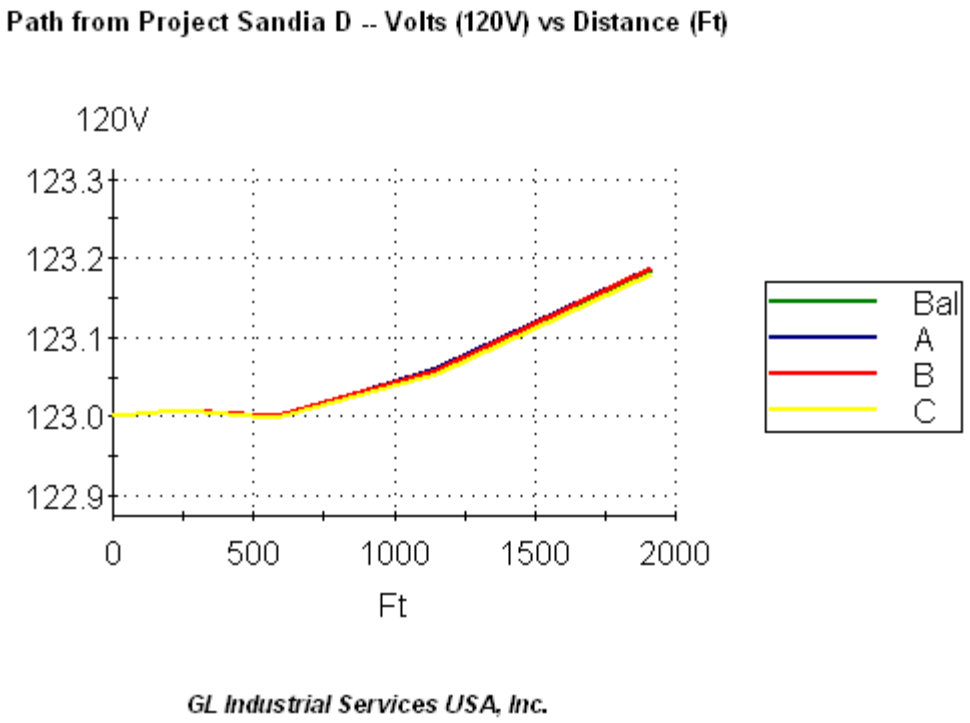


The model voltages at the point of interconnection are:

Phase A – 122.9 volts Phase B – 122.9 volts Phase C – 122.9 volts Balanced – 122.9 volts

The voltages on Innovation Feeder 12 for the loss of Four Hills Substation contingency prior to the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 12 - Innovation Feeder 12 voltage drop from Innovation Substation to the Project Sandia D POI for the loss of Four Hills Substation for daylight hours minimum load on May 30, 2009. Project Sandia D is ON, 100% power factor.



The model voltages at the point of interconnection are:

Phase A – 123.2 volts Phase B – 123.2 volts Phase C – 123.2 volts Balanced – 123.2 volts

The voltages on Innovation Feeder 12 for the loss of Four Hills Substation contingency after the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion, the output from Project Sandia D does cause the voltage on Innovation Feeder 12 and on Four Hills Feeder 14 for contingency conditions to increase. However, the voltage stays within the PNM criteria of ANSI C84.1 and is acceptable.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Sandia D is served by Innovation Feeder 12, and there are no voltage regulators installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

As seen in Tables 7 -10, the SynerGEE modeling shows the LTC did not change positions for 5,000 KVA source on the feeder for high or low load periods. This LTC operation is not considered an adverse impact.

Project Sandia D was modeled as a source on Innovation Substation connected to the end of Innovation Feeder 12. The SynerGEE model included the substation transformer and Innovation Feeders 11, 12 and 13. The substation bus voltage and load tap changer position for maximum daylight hours load for 2009 with and without Project Sandia D 5MW, per the SynerGEE model, are shown in Tables 7 and 8.

Table 7 ***- Innovation Substation with Project Sandia D OFF for daylight hours maximum load on August 4, 2009***

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.5	122.1	122.5	122.4
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 7. The voltages at Innovation Substation prior to the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8 ***- Innovation Substation with Project Sandia D ON, 100% power factor for daylight hours maximum load on August 4, 2009***

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.6	122.3	122.6	122.5
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 8. The voltages at Innovation Substation after the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The Innovation Feeder 12 voltage for the feeder minimum daylight hours load for 2009 with and without Project Sandia D, per the SynerGEE model, are shown in Graphs 9 and 10.

Table 9 ***- Innovation Substation with Project Sandia D OFF for daylight hours minimum load on May 30, 2009***

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.6	122.5	122.6	122.5
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 9. The voltages at Innovation Substation prior to the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 10 ***- Innovation Substation with Project Sandia D ON, 100% power factor for daylight hours minimum load on May 30, 2009***

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.7	122.6	122.7	122.7
LTC position	neutral	neutral	neutral	

The model voltages at the substation bus are shown in Table 10. The voltages at Innovation Substation after the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Innovation Substation bus stayed within the PNM criteria of ANSI C84.1 regardless of Project Sandia D output.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most

common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load cannot be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Innovation Substation bus was fixed at 123 volts with and without Project Sandia D output for maximum and minimum load periods. Table 11 summarizes the balanced voltage and the calculated voltage flicker. Table 12 is based on the GE flicker graph.

Table 11 ***- Voltage flicker at the POI due to Project Sandia D***

	Project Sandia D POI Bus Voltage	
	Minimum	**Maximum**
Without Project	123.0	123.0
With Project	123.2	123.2
% Voltage Flicker	**0.16**	**0.16**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 12 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	**Border Line of Irritation**
0.16	Not visible	No Irritation
0.16	Not visible	No Irritation

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 11 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 12. Results are less than the 6% criteria; therefore distribution voltage flicker resulting from changes in Project Sandia D output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Sandia D POI to the substation were reviewed using the SynerGEE feeder model with and without Project Sandia D's maximum output of 5,000 KVA AC.

There were no conductor loading problems from the POI to the substation on Innovation Feeder 12 with or without Project Sandia D.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no vars. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Innovation Feeder 12 has one 1800 KVAR RCCS controlled capacitor bank. The modeled August 2009 peak load on the feeder, with Project DG1 on, was 2,760 KW – j 156 KVAR or 2,765 KVA at a 99.8 leading power factor (-99.8 PF). The 1,800 KVAR RCCS controlled capacitor bank was assumed to be energized during the peak load period. Project Sandia D would change the apparent feeder loading to -2,240 KW - j 159 KVAR or 2,245 KVA at 99.8% leading power factor (-99.8% PF). This power factor value exceeds the RCCS power factor control point, but all capacitors are energized prior to this condition, therefore any issues addressed would be driven by pre-existing conditions. Should the RCCS system switch the 1,800 KVAR capacitor bank off, the voltages on the circuit are within the PNM voltage criteria (ANSI C84.1) and are acceptable.

This study also examined switching the RCCS controlled capacitor bank under minimum load conditions to see what affect this would have on the system. At minimum feeder load, with the RCCS capacitor bank offline, the voltage on the feeder is within the PNM voltage criteria (ANSI C84.1) at the POI and is acceptable. Should the RCCS controlled capacitor bank be switched on with Project Sandia D, the feeder voltage remains within the PNM criteria of ANSI C84.1 and is acceptable.

For the loss of Innovation Substation, Four Hills Feeder 14 provides backup support to Innovation Feeder 12. While Four Hills Feeder 14 is providing backup support to the area, there are two 1,800 KVAR RCCS capacitor banks on the feeder. During the contingency analysis for the loss of Innovation Substation, one 1,800 KVAR capacitor bank was assumed to be on for the peak load timeframe and the RCCS capacitor banks were assumed to be off for the minimum load timeframe. For this analysis the voltages are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable for these configurations. This study also examined switching the RCCS controlled capacitor banks under maximum and minimum load conditions to see what affect this would have on the system. For both peak and minimum conditions, switching either one or both of the RCCS capacitor banks does not cause the voltages on the feeder to exceed the ANSI C84.1 voltage criteria and is acceptable.

For the loss of Four Hills Substation, Four Hills Feeder 14 is backed up by Innovation Feeder 12. While Innovation Feeder 12 is providing backup support to the area, there are two 1,800 KVAR RCCS capacitor bank on the feeder. During the contingency analysis for the loss of Four Hills Substation, one 1,800 KVAR capacitor bank was assumed to be on for the peak load timeframe and the RCCS capacitor banks were assumed to be off for the minimum timeframe. For this analysis the voltages are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable for these configurations. This study also examined switching the RCCS controlled capacitor banks under maximum and minimum load conditions to see what affect this would have on the system. For both peak and minimum conditions, the voltage remains within the voltage criteria and are acceptable.

9.0 PROTECTION

9.1 Normal Configuration – Service from Innovation Feeder 12

Innovation Substation feeder 12 is protected by a 1200 amp breaker in metal clad switchgear with an ABB, DPU2000R extremely inverse phase overcurrent relay, a very inverse ground overcurrent relay and reclosing relay. The switchgear bus and feeder backup protection is an ABB, DPU2000R extremely inverse phase relay and an ABB, DPU2000R very inverse ground relay. The transformer protection is an ABB, TPU2000R differential relay. The Sandia D Project PV system will be connected to the system approximately 0.22 miles from the Innovation substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 4300 amps of fault current on the 200V distribution system as provided by the interconnection requestor.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 5 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions

from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

The Sandia D Project does not require any system protection improvements to be made to the Innovation Substation feeder 12.

9.2 Normal Feeder as Backup Feeder - Innovation Feeder 12 picks up 55% of Four Hills 12 and 100% of Four Hills 14

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 4300 amps of fault current on the 200V distribution system as provided by the interconnection requestor.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 5 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

The Sandia D Project does not require any system protection improvements to be made to the Innovation Substation feeder 12 when it is a backup feeder for Four Hills 14 and Four Hills 12.

9.3 Contingency Configuration – Four Hills Feeder 14 picks up Innovation Feeder 12

Four Hills Substation feeder 14 is protected by a 1200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three ABB, CA differential relays. The Sandia D Project PV system will be connected to the system approximately 2.78 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in SynerGEE to produce the 4300 amps of fault current on the 200V distribution system as provided by the interconnection requestor.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 5 MW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

The Sandia D Project does not require any system protection improvements to be made to the Four Hills Substation feeder 14 under the contingency configuration.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Sandia D output exceeds the 2009 maximum and minimum load on Innovation Feeder 12 during daylight hours. No Innovation Feeder 12 equipment overloads were identified.

Project Sandia D output exceeds the 2009 maximum and minimum load on Four Hills Feeder 14 during daylight hours. No Four Hills Feeder 14 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for

billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

The following cost estimates for communication have been developed:

ONE-TIME Equipment COST	$ 35,000
One-Time Labor Cost	$ 10,000
MONTHLY Recurring O&M	$ 3,500

The breakdown of the ONE-TIME Equipment cost:

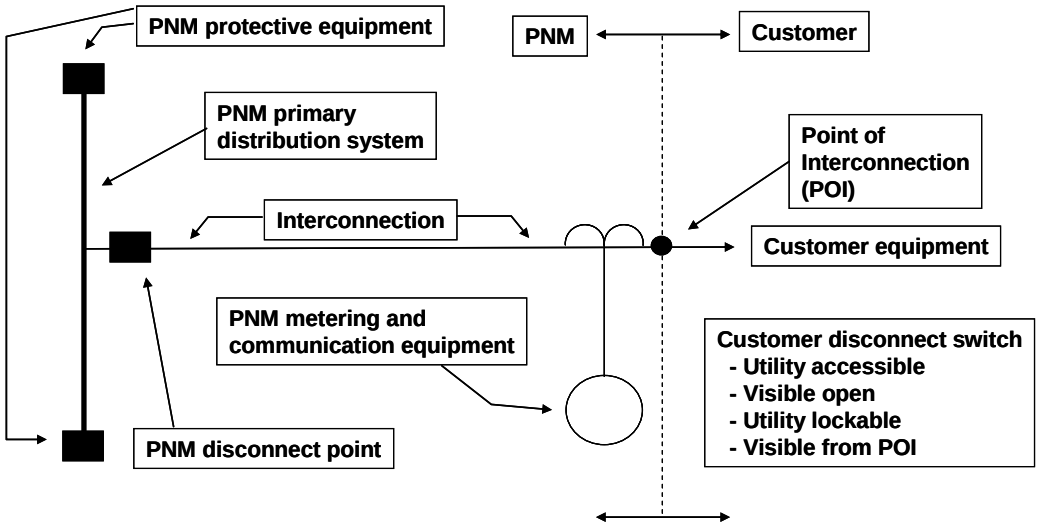
Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$ 20,000
Channel Bank Equipment	$ 10,000

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 2 is a one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 2 ***– Typical Project Interconnection***

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and

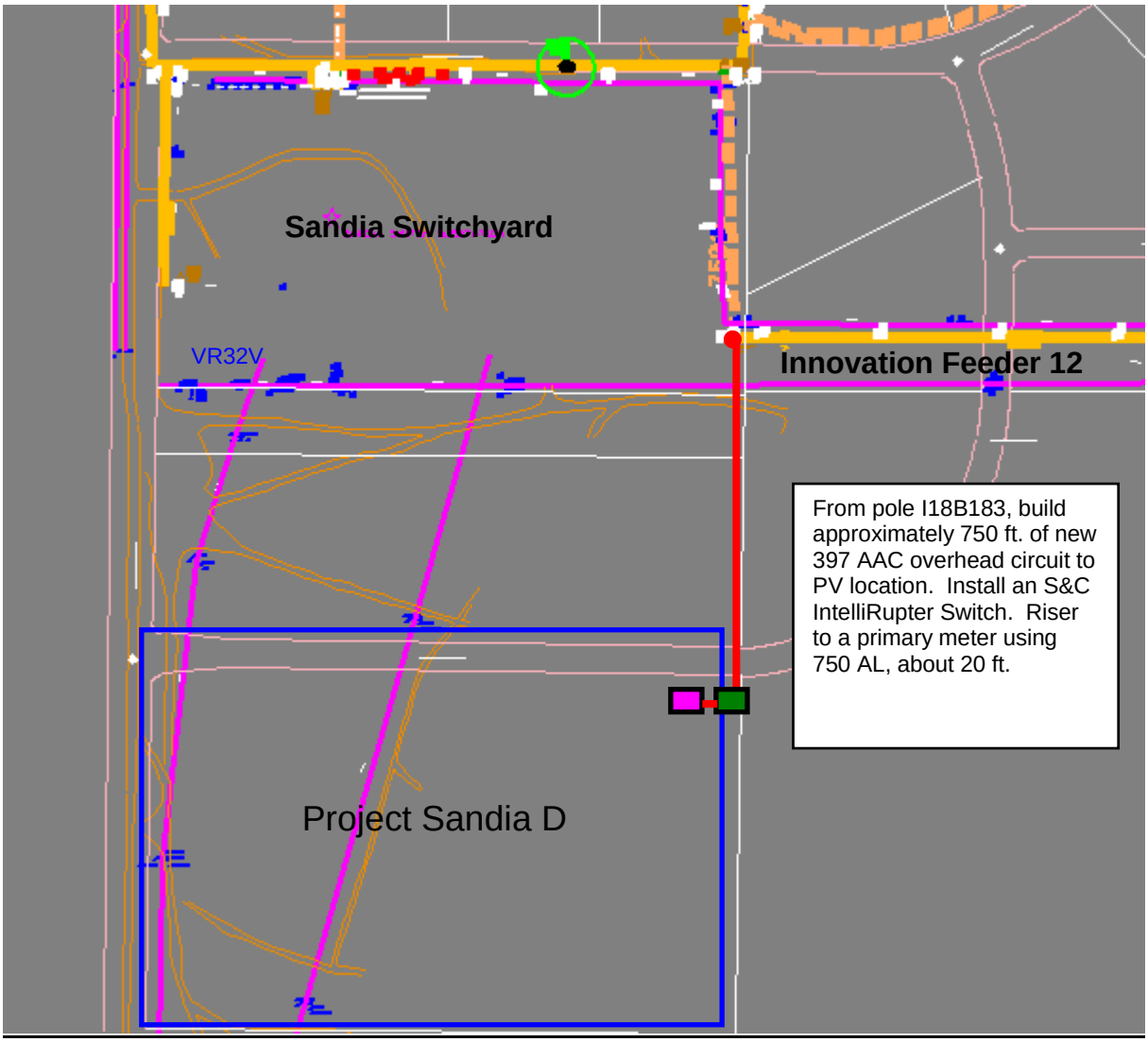
remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

To connect Project Sandia D to the PNM distribution system, a line extension is required. The interconnection consists of:

- From pole I18B183, build approximately 750 ft. of new 397 AAC overhead circuit to PV location (See Figure 3).
- Install One S&C IntelliRupter switch (See Figure 3).
- Install riser to primary meter, about 20 ft, using 750 AL (See Figure 3).

Figure 3 ***– Line Extension to connect Project Sandia D to Innovation Feeder 12***



The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 13.

Table 13 ***- Project Sandia D Interconnection Cost***

	ESTIMATED COSTS 2010$
PNM disconnect point (Intellirupter)	$ 54,500
Interconnection (Line Construction)	$ 54,000
PNM Primary metering	$ 18,500
Communications	$ 45,000
TOTAL	**$ 172,000**

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

The proposed location for Project Sandia D is located on a parcel of land that has multiple transmission line easements with existing transmission lines crossing the property. Facilities proposed to be built within those easements must get approval by the Public Service Company of New Mexico.

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This may also involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition is not expected to be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA).

16.0 CONCLUSIONS

Project Sandia D does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Innovation Feeder 12. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. There is one remotely controlled capacitor bank on the feeder associated with Project Sandia D. The automatic control of voltage by the substation LTC may cause the LTC to operate, but this is not anticipated to be an adverse effect. The Project output will cause a flow of electricity from the distribution system through the substation transformer, the difference is minimal, therefore no transmission voltage issues are anticipated. Analysis showed that the Project output did not cause conductor ratings to be exceeded. Finally, analysis shows that Project Sandia D output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Sandia D and has determined that there are no adverse impacts associated with a 5,000 KVA AC source connected to Innovation Substation connected to Innovation Feeder 12.

Distribution Planning has determined that system upgrades are not required to ensure that electric service to all customers on Innovation Substation is maintained within established PNM voltage, equipment and fault protection criteria.

XXX

Project Sandia B
5,000 kVA PV Generation Project

Small Generator Interconnection
System Impact Study

(SGI-PNM-2010-15)

June 2011

Prepared by:

TRC Engineers, Inc.

Under Contract With:

Public Service Company of New Mexico

Transmission/Distribution Planning and Contracts

Electric Services
Transmission Operations

Foreword

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EXECUTIVE SUMMARY

XXX submitted a Small Generator Interconnection Request (SGIR) for the interconnection of an inverter based, grid-connected photovoltaic (PV) system with a nominal rating of 5,000 kVA AC to the Public Service of New Mexico 12.47kV distribution primary system. The SGIR identified the proposed PV system as Project Sandia B (Project). In the SGIR the Project requested to be connected near PNM's Innovation Substation. XXX's application was submitted based on Public Service Company of New Mexico's Open Access Transmission Tariff (OATT), Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW. This Interconnection System Impact Study for the Project was performed by TRC for Public Service Company of New Mexico Transmission/Distribution Planning and Contracts (Distribution Planning) as part of the SGIP process.

The estimated cost of connecting the Project to PNM's distribution primary system is:

	ESTIMATED COSTS (2011 Dollars)	**Estimated Construction Time**
PNM Disconnect Point Switch (Intellirupter)	$ 70,400	~26 Weeks lead time ~4 Days to build
Interconnection (Distribution Line Construction)	$ 24,580	~1 Week lead time ~7 Days to build
Raise 46kV Subtransmission Line	$ 75,000	~4 Weeks lead time ~3 Days to build
PNM Primary Metering	$ 26,000	~16 Weeks lead time ~3 Days to build
Communications	$ 45,000	~16 Week lead time ~3 Weeks to build
Protection	$ 0	
Rights-of-Way	$6,500	
Environmental	$12,200	
TOTAL	**$ 259,680**	**6-7 months for lead time and final build out**

The technical data notes for the Satcon Powergate Plus 500 kW inverter provided by XXX with its SGIR were used to prepare this report. The technical data provided indicated that Satcon Powergate Plus 500 kW inverter is UL 1741 compliant.

This System Impact Study (Study) evaluates the impacts to the electrical system resulting from the Project's requested interconnection of an electric generation source to the distribution primary system. The electric system impacts considered in this Study were steady state voltage levels, equipment ratings and loadings, fault current levels and protective device adequacy during normal distribution system operating (N-0) conditions and for contingency (N-1) conditions. The generation source for the Project evaluated in this Study is a photovoltaic PV generation resource with a nominal 5,000kVA$_{AC}$ capacity that is connected to the 12.47kV distribution primary using UL1741 compliant DC/AC inverters.

XXX has also proposed connection of an additional 5,000kVA PV generating facility at Innovation Substation. The impacts of this second XXX project, identified as Project Sandia D, were evaluated by PNM in the Small Generator Interconnection Feasibility Study, SGI-PNM-2010-14, prepared by PNM. In addition to the 5,000kVA Sandia D PV facility, two 1,000kVA PV generating plants, DG1 and DG2, have also been previously studied by PNM for interconnection with Innovation Substation feeders. This study and the analyses for the Sandia B Project were conducted with the 5,000kVA Project Sandia D and the two 1,000kVA PV plants, DG1 and DG2, in service and producing at their rated levels.

The Sandia B Project does not have an adverse impact on the operations of the PNM distribution system for the conditions evaluated during either normal or N-1 contingency operations. The findings of this Study are summarized below:

1. The Project location will result in an interconnection with Innovation Substation Feeder 13.
2. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
3. Power production by the Project may cause automatic control of voltage by the substation LTC to cause the LTC to operate but these operations are judged to not have an adverse impact on either power quality or substation maintenance.
4. Project output variations due to clouds are not anticipated to cause objectionable levels of voltage flicker.
5. Project output did not cause conductor ratings to be exceeded.
6. All capacitors included in evaluating the Project's impact are fixed capacitors. Project output did not cause voltages outside PNM's ANSI C84.1 criteria or unacceptable power factor values.
7. The Project contribution to fault current does not require system protection upgrades to be made to the Innovation Feeder 13 for either normal or contingency circuit configurations.

8. Project output will cause a flow of electricity from the distribution system to the transmission system through the substation transformer, but this is not anticipated to cause an adverse impact on the transmission system.

The results of the analyses conducted for this report conclude that there are no adverse voltage or equipment loading impacts associated with Project Sandia B's 5,000 kVA_{AC} source connected to Innovation Substation when connected to Innovation Feeder 13.

The results of the analyses further conclude that connection of the Project will not require system protection upgrades to ensure that reliable electric service to all customers served from Innovation Substation is maintained within established PNM voltage, equipment and fault protection criteria.

1.0 INTRODUCTION

The purpose of this Study is to determine the electrical system impacts that will result from connecting the Project's 5,000kVA photovoltaic (PV) electric generation source to the distribution primary system. The PV generation source consists of 10-500kW UL 1741 compliant inverters that convert the DC power produced by the PV modules to AC voltage and current. Electric system impacts considered are steady state voltages, equipment ratings and fault protection. With the Project's 5,000kVA generating resource in service and operational, analyses will be conducted for the following scenarios:

- High load on the distribution system for both normal and N-1 contingency configurations with Project Sandia B, as well as Project Sandia D, DG1 and DG2, in service and operational,
- Low load on the distribution system for both normal and N-1 contingency configurations with Project Sandia B, as well as Project Sandia D, DG1 and DG2, in service and operational.

Study recommendations will be based on analyses results and will be made with the objective of assuring that reliable electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

The Project proposes to connect a 5,000 kVA AC PV facility to PNM's 12.47kV distribution system near PNM's Innovation Substation in the southeast area of Albuquerque, NM. Innovation Substation is collocated with PNM's Sandia Station. The Project will be located approximately 1,400 feet east of PNM's Sandia Station as shown in Figure 1. The circuit distance from Innovation Substation to the Project point of interconnection (POI) is about 2,550 ft. or 0.5 miles. The shaded area south of Sandia Station indicates the location of the proposed XXX Sandia Project D, whose presence is taken into account for the Study.

3.0 SYSTEM CONFIGURATION

At the time of the Study, the location of requested point of interconnection (POI) for the Project is served by Four Hills Feeder 12. The in-Service date for the interconnection is Dec. 1, 2011. By this date, the distribution system configuration will be different due to the recent completion of the Innovation Substation. By the proposed interconnection date Innovation Substation will be complete and will be carrying load transferred from Four Hills Feeder 12. This study assumes that the portion of the existing Four Hills Substation Feeder 12, that the Project will connect to, will become a portion of Innovation Substation Feeder 13 for normal service conditions. All loads stated in this study are based on a SynerGEE model that uses 2009 loads for the feeders in their then current system configuration as the base.

In June 2010, PNM evaluated two 1,000 kVA PV installations, one on Lenkurt Feeder 14 (Project DG2) and the other on Four Hills Feeder 14 (Project DG1). The studies for Project DG1 and DG2 concluded that there were no adverse impacts on their respective feeders for normal or contingency configurations. In April 2011 PNM evaluated the impact of connecting the 5,000kVA Project Sandia D to Innovation Substation Feeder 12. This study concluded that there were no adverse impacts resulting from the interconnection of Project Sandia D. For this study, Projects DG1, DG2 and Sandia D are assumed to be in service and producing power at their rated levels, and connected to the Innovation 11 and 12 feeders.

Figure 1 – Project Location

The Project is a large PV source that will ultimately be connected to Innovation Feeder 13 and Innovation Substation during normal utility system operations. Table 1 shows the rating of Innovation Substation transformer as determined by the EPRI Ptload software application that PNM uses to establish normal and emergency load ratings for distribution substation transformers.

Table 1 – Substation Transformer Nameplate Versus Ptload Rating

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Innovation	33.6	40.8	43.2	115 -12.47

Table 2 shows the anticipated loads for Innovation Substation and feeders based on 2009 peak summer loads for the adjacent Lenkurt and Four Hills substation feeders that were transferred to the recently completed Innovation Substation and Innovation Substation Feeders 11 and 12. The load modeled for the proposed Innovation Feeder 13 will be transferred from the existing Four Hills 12 feeder. The feeder configurations used in the SynerGEE models for this study assume that Innovation Substation and its three new feeders are in-service. The peak loads listed are individual peak loads and are not coincident with PNM's 2009 system wide peak demand.

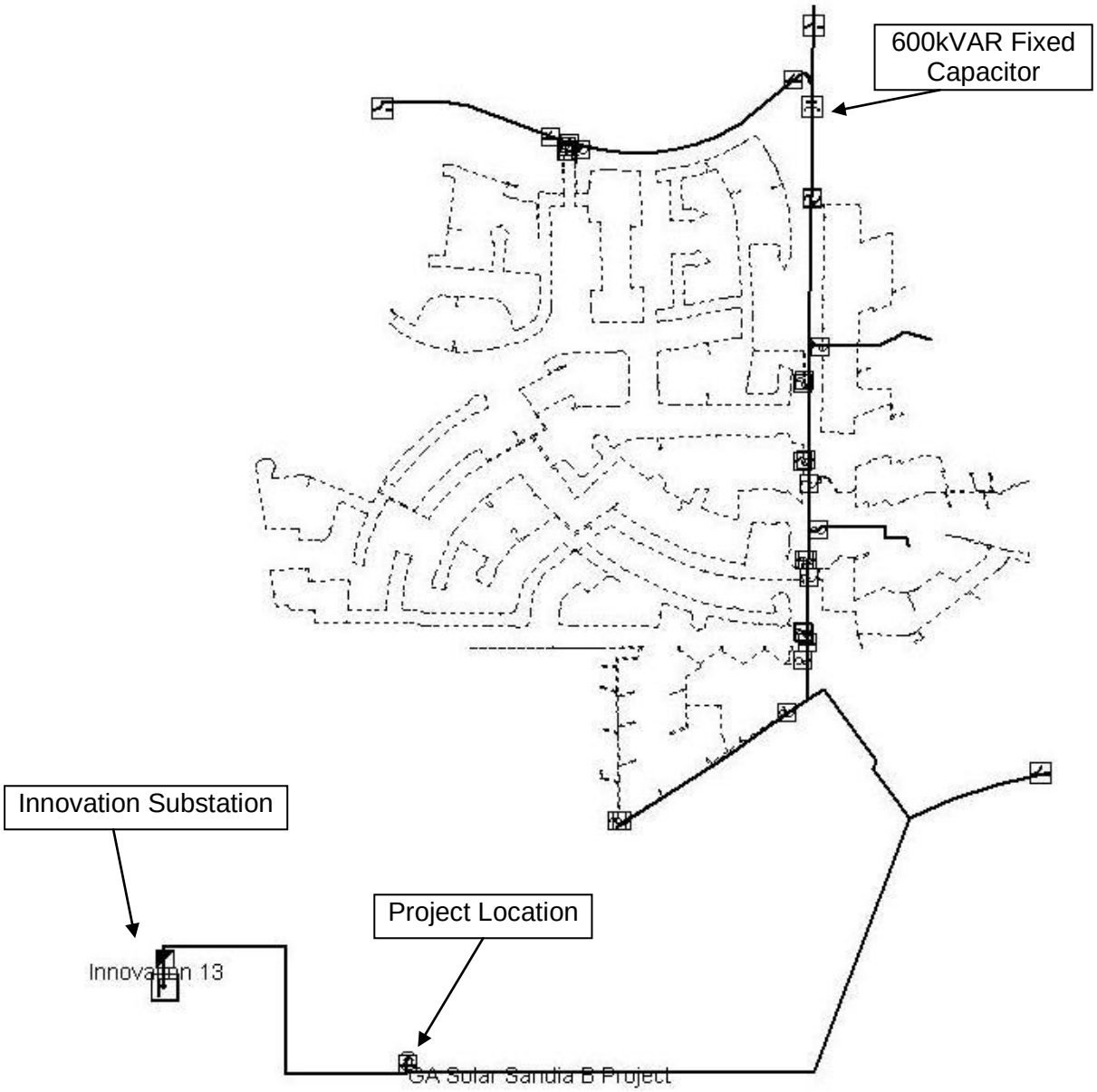
Table 2 – Modeled July 2009 Non-coincident Peak Loads

Feeder	Modeled July 2009 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Innovation 11	4,406	2,046	4,858	90.7
Innovation 12	3,759	-156	3,762	-99.9 *
Innovation 13	2,692	541	2,746	98.0
Innovation Substation	10,857	2,431	11,126	97.6

* The negative sign on the power factor implies a leading power factor and that the feeder is exporting reactive power to the substation bus.

Figure 2 is a map of the SynerGEE model of the Innovation Substation Feeder 13 configuration used for the Study. In Figure 2 solid lines represent three-phase portions of the feeder. Dashed lines represent single and two-phase portions of the feeder.

Figure 2 – SynerGEE Model Of Innovation Feeder 13



Innovation Feeder 13 will have one fixed, 600kVAR capacitor near the end of the feeder at the time of the Sandia B Project's proposed in service date. Four Hills Feeder 12, which will be the back-up feeder for Innovation Feeder 13, will have two fixed, 600kVAR capacitors at the time of the proposed interconnection date. The capacitors for Innovation 13 and Four Hills 12 were modeled as being on-line and in service for all operating conditions addressed in this study.

Table 3 – Status of Capacitors

Capacitor	KVAR Size	Fixed or Switched	Status	
			Min load	Max Load
Innovation 13				
C277	600	F	ON	ON
Four Hills 12				
C462	600	F	ON	ON
C523	600	F	ON	ON

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours – the first condition is the peak load on each study area distribution circuit and the second condition is the minimum load on each study area distribution circuit. The times for maximum and minimum load are non-coincident for the distribution circuits.

The daylight hours are based on sunrise and sunset time for January through December in Albuquerque using 2009 data. 2009 peak load data were used for this study because 2010 peak load data were not available when the Sandia B SGIP was received by PNM.

Table 4 shows the daylight hours time (mountain time zone) considered for each month when determining the maximum and minimum loading used in a PV system impact study.

Table 4 – Daylight Time Ranges Considered for PV Studies

Daylight Time Ranges for PV Studies		
7 AM - 7 PM	**8 AM – 5 PM**	**8 AM – 4 PM**
April	March	January
May	September	February
June	October	November
July		December
August		

The maximum and minimum daylight hours loading on Innovation Feeder 13 and its backup Four Hills Feeder 12 are shown in Table 5: Although a PV system may not be producing its maximum output at the time of feeder or substation maximum and minimum loads, the analysis of circuit performance assumes PV system maximum output.

Table 5 – Max/Min Daylight Hours Load

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Innovation 13								
August 4, 2009	6 PM	2,692	541	2,746	98	144	71	158
September 20, 2009	8 AM	678	-631	926	-73.2 *	49	30	48
Four Hills 12								
August 4, 2009	6 PM	3,321	397	3,345	99.3	141	179	134
September 20, 2009	8 AM	810	-1,019	1,302	-62.2 *	65	51	62

* The negative sign on the power factor implies a leading power factor and that the feeder is exporting reactive power to the substation bus.

As shown in Table 5, at its 5,000kVA maximum output, the power produced by Project Sandia B exceeds the load on Innovation Feeder 13 during both peak and minimum load conditions. Consequently the Project will cause power to flow into Innovation Substation 12.47kV bus. Table 6 shows the maximum and minimum daylight hours load modeled on the Innovation Substation transformer.

Table 6 – Innovation Substation Modeled Maximum and Minimum Loads

	KW	KVAR	KVA	Power Factor	Phase Amps		
					A	B	C
Maximum	10,857	2,431	11,126	97.6	496	542	503
Minimum	4,388	1,088	4,521	97.1	227	235	220

At its maximum power levels the output of the Project exceeds the minimum daylight hours load on Innovation Substation by about 600kW. This will result in power flowing from the distribution system through the substation transformer to the transmission system. When the maximum power produced by the previously studied DG1, DG2 and Sandia Project D PV generating facilities is included, the total power generated by all resources connected to Innovation Substation exceeds the total substation load by about 7,610kW during low load periods and 1,143kW during peak load periods.

4.1 Voltage impacts on the transmission system

The total load on the Innovation Substation transformer is less than the rated output of the Sandia B Project during minimum load periods resulting in approximately 600kW flowing from the distribution system to the transmission system during low load periods. The combined outputs of the Project Sandia B, Project Sandia D, DG1 and DG2 resources exceed the load on Innovation Substation by approximately 1,140kW and 7,610kW during both peak and minimum load periods respectively. No transmission related problems are anticipated to be associated with the normal operation of the Sandia B or the other generating resources at Innovation Substation considered in this study.

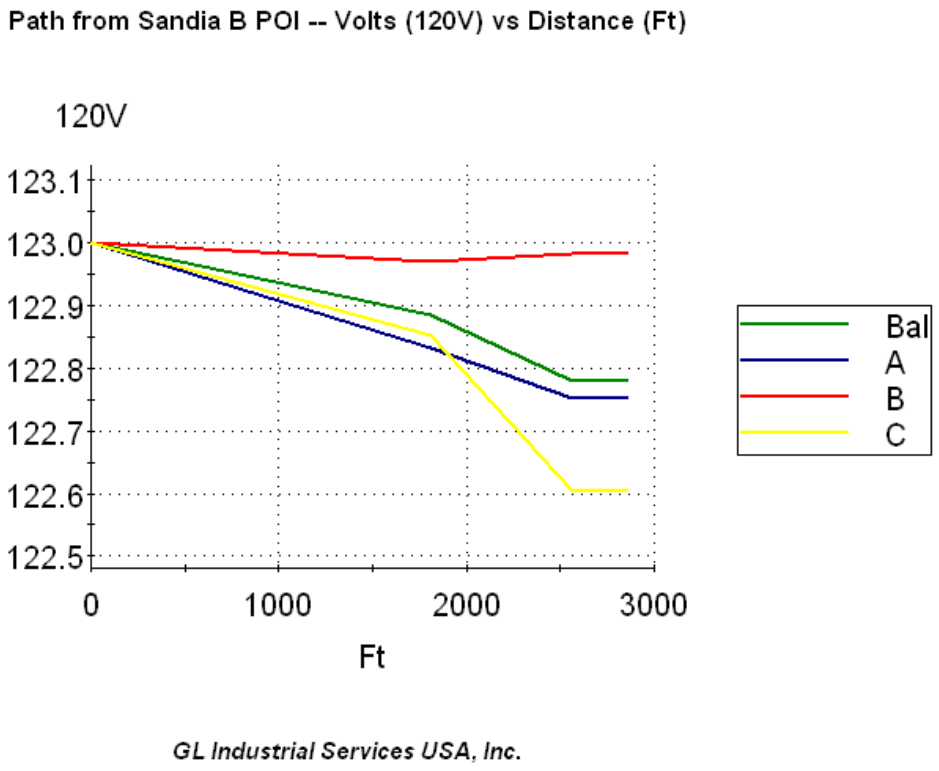
4.2 PV Power Factor Setting for Voltage Screen for PV System Impacts

The electric distribution system was screened to determine if there are any adverse voltage impacts resulting from Project Sandia B injecting energy during peak load and minimum load periods. The screening analysis was done for both the normal system configuration and for outage contingency configurations. Project Sandia B was evaluated operating at a 100% power factor to determine if system criteria limits were violated. The modeled system was evaluated with and without Project Sandia B for maximum and minimum load during normal and contingent conditions. The evaluation with Project Sandia B operating at 100% power factor for maximum load during the studied normal and contingency configuration for peak and minimum load conditions shows that the distribution system voltage is within the ANSI C84.1 criteria and is acceptable.

4.3 Voltage Impacts for Peak Feeder Loads for Normal Configuration

The graphs of the voltages for Innovation Feeder 13 during the modeled 2009 peak daylight hours load with and without Project Sandia B are shown in Graphs 1 and 2. Initially the majority of the load on Innovation Feeder 13 will be residential in nature. However, future growth on the Feeder 13 may include commercial as well as industrial loads. Graph 1 shows the system voltages prior to the interconnection of the Project B 5,000kVA of PV generation. Graph 2 shows the impact of the Sandia Project B interconnection on voltages.

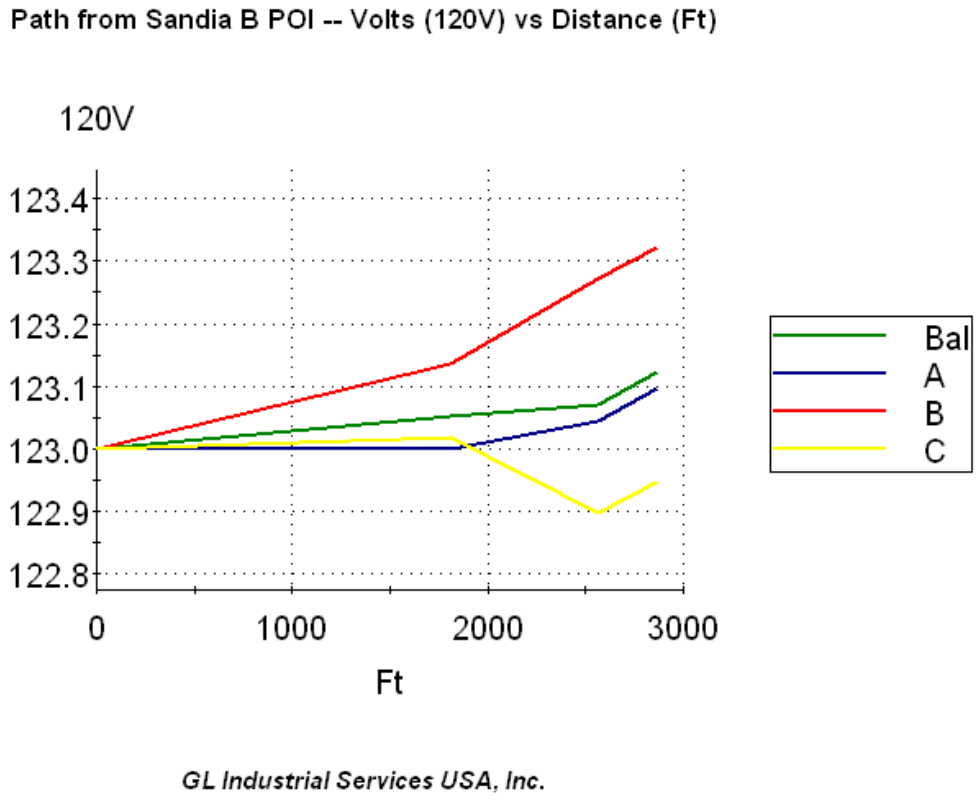
Graph 1 – Innovation Feeder 13 Voltage Profile From Innovation Substation to Project Sandia B POI for Peak Load. Project Sandia B is OFF.



The voltages at the point of interconnection are:
Phase A – 122.8 volts Phase B – 123.0 volts Phase C – 122.6 volts Balanced – 122.8volts

The voltages on Innovation Feeder 13 prior to the installation of Project Sandia B are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 – Innovation Feeder 13 Voltage Profile From Innovation Substation to Project Sandia B POI for Peak Load. Project Sandia B is ON, 100% Power Factor.



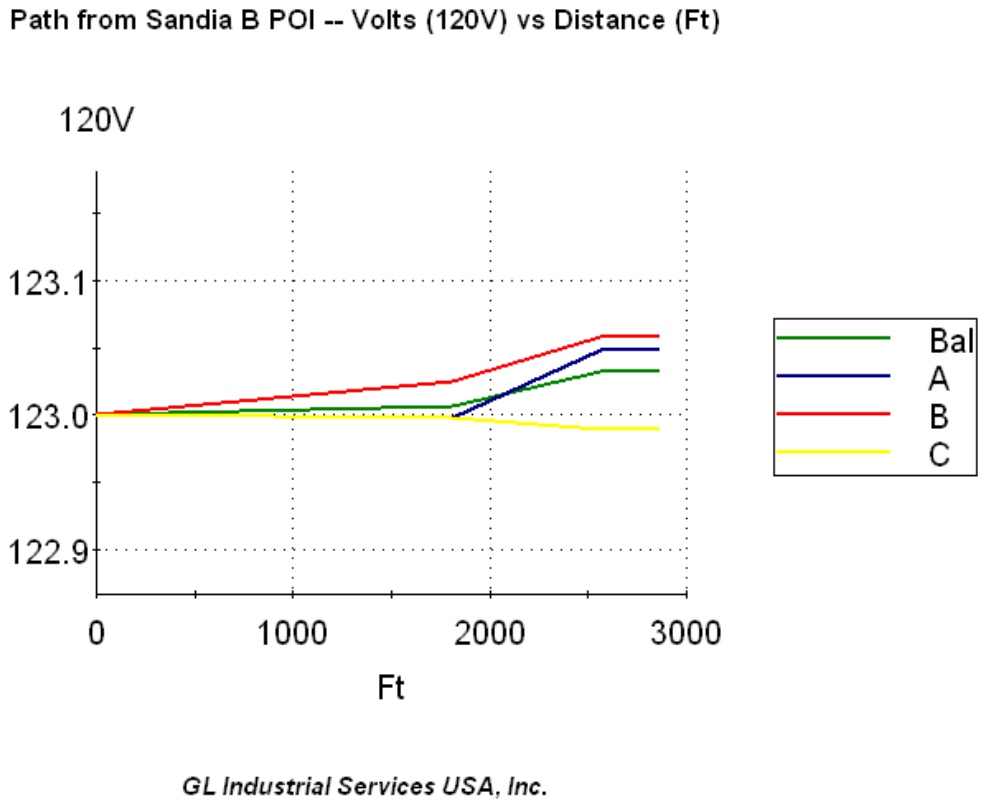
In Graph 2 the voltages at the point of interconnection are:
Phase A – 123.1 volts Phase B – 123.3 volts Phase C – 122.9 volts Balanced – 123.1 volts

The voltages on Innovation Feeder 13 after the installation of Project Sandia B are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.4 Voltage Impacts for Minimum Daylight Hours Load for Normal Configuration

The Innovation Feeder 13 voltage for the feeder daylight hours, for the modeled 2009 minimum load, with and without Project Sandia B is shown in Graphs 3 and 4.

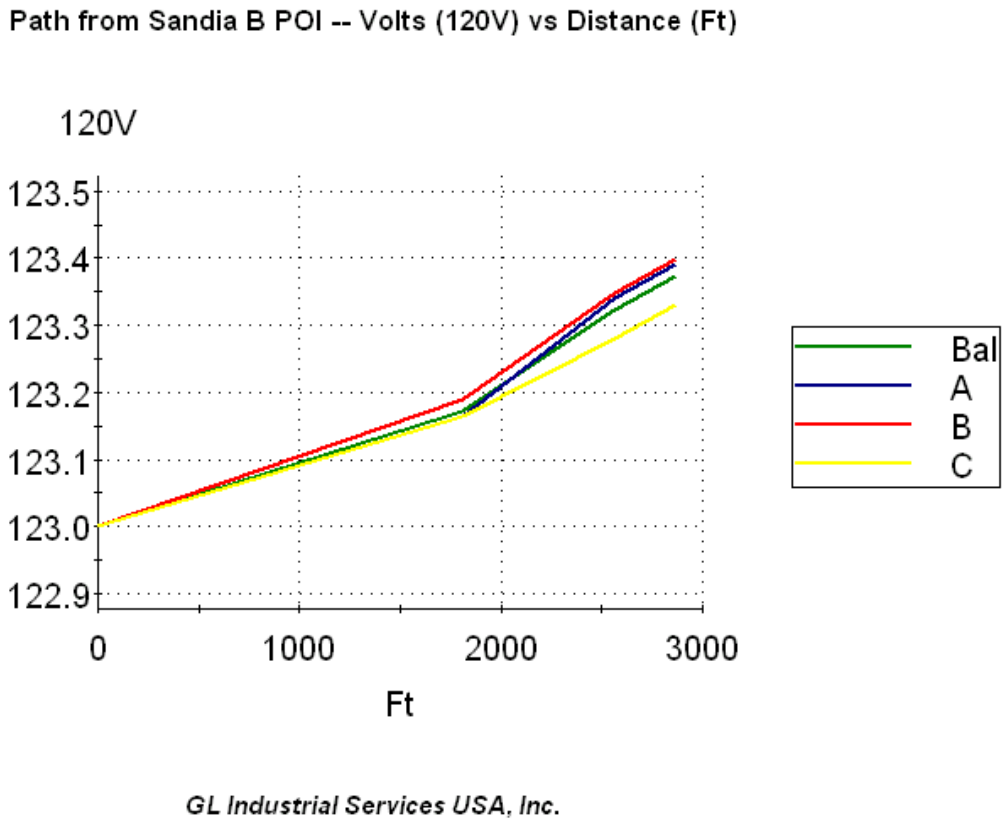
Graph 3 – Innovation Feeder 13 Voltage Profile From Innovation Substation to the Project Sandia B POI for Minimum Load. Project Sandia B is OFF.



The voltages at the point of interconnection are:
Phase A – 123.0 volts Phase B – 123.1 volts Phase C – 123.0 volts Balanced – 123.0Volts.

The voltages on Innovation Feeder 13 in its normal configuration prior to the installation of Project Sandia B are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 – Innovation Feeder 13 Voltage Profile From Innovation Substation to the Project Sandia B POI for Minimum Load. Project Sandia B is ON, 100% Power Factor.



The voltages at the point of interconnection are:
Phase A – 123.4 volts Phase B – 123.4 volts Phase C – 123.3 volts Balanced – 123.4 volts.

The voltages on Innovation Feeder 13 in its normal configuration after the installation of Project Sandia B are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

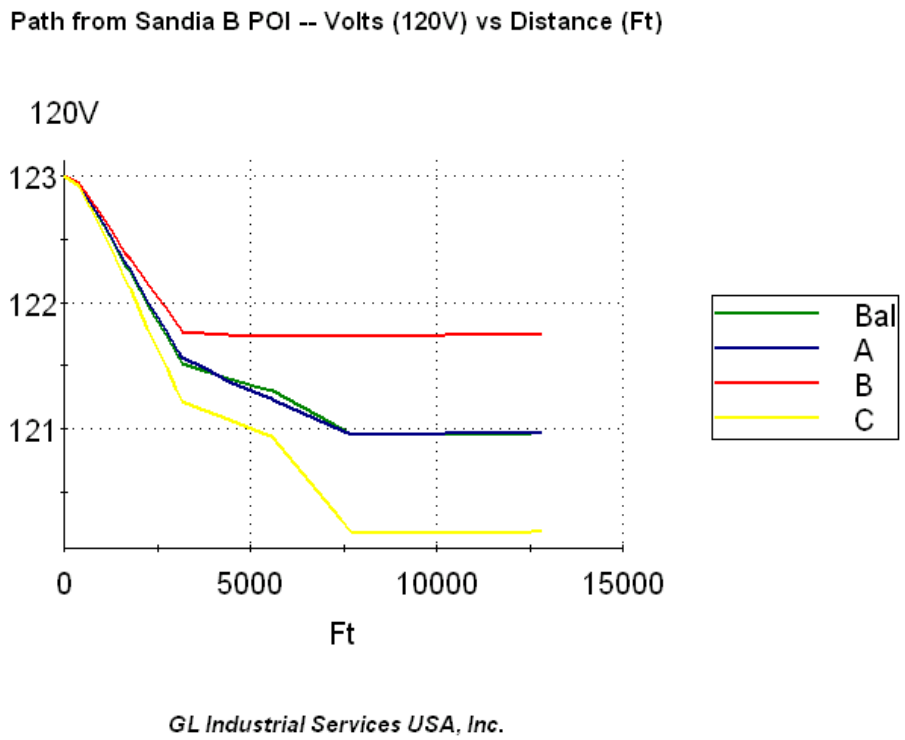
4.5 Voltage Impacts for Maximum Daylight Hours Load for Contingency Configuration

Four Hills Substation Feeder 12 is the backup feeder for an outage of Innovation Feeder 13. Conversely, Innovation 13 provides backup for Four Hills 12. Presently, there are two possible scenarios for contingency configurations that the interconnection of Project Sandia B can contribute to. The first is for the loss of Innovation Substation, the second is for the loss of Four Hills Substation. Table 5 shows the maximum and minimum Four Hills Feeder 12 load data that were used for the contingency evaluations.

4.5.1 Contingency Configuration – Loss of Innovation Substation, Maximum load

For the loss of the Innovation Substation, 100% of Innovation Feeder 13 is transferred to Four Hills Substation through 100% of the load on Four Hills Feeder 12. Voltages for the modeled Innovation 13 and Four Hill 12 peak feeder loads for an Innovation Substation outage configuration are shown in Graphs 5 and 6. Graph 5 shows the voltages without Sandia Project B and Graph 6 shows the voltages with the Sandia Project B in service. The circuit distance from Four Hills Substation to the Project point of interconnection is about 13,233 feet or 2.51 miles.

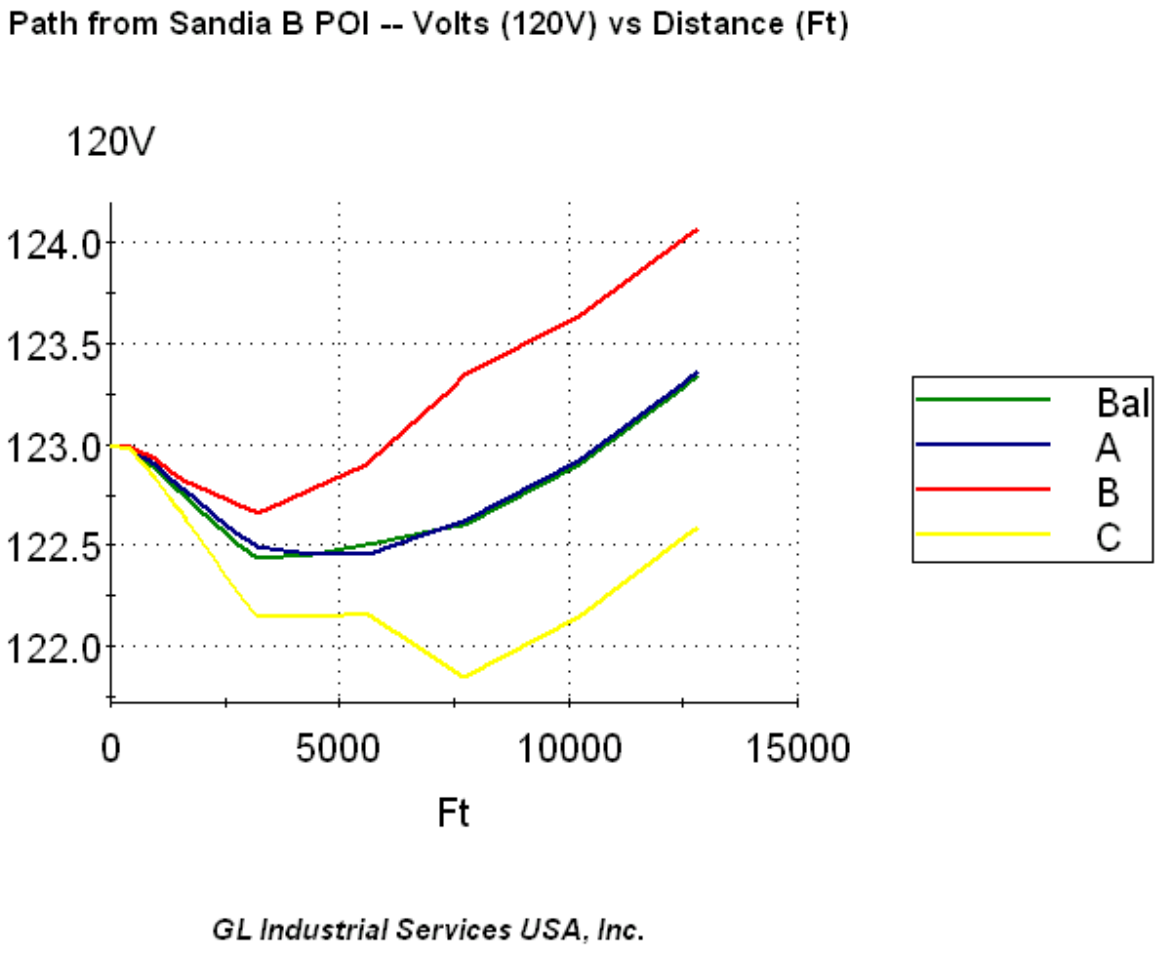
Graph 5 – Four Hills Feeder 12 Voltage Profile from Four Hills Substation to the Project Sandia B POI for the loss of Innovation Substation for Peak Load. Project Sandia B is OFF.



The voltages at the point of interconnection are:
Phase A – 121.0 volts Phase B – 121.7 volts Phase C – 120.2 volts Balanced – 121.0 volts

The voltages on Four Hills Feeder 12 for the loss of Innovation Substation prior to the installation of Project Sandia B are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 6 – Four Hills Feeder 12 Voltage Profile From Four Hills Substation to the Project Sandia B POI for the Loss of Innovation Substation for Peak Load. Project Sandia B is ON, 100% power factor.



The voltages at the point of interconnection are:
Phase A – 123.4 volts Phase B – 124.1volts Phase C – 122.6 volts Balanced – 123.3 volts

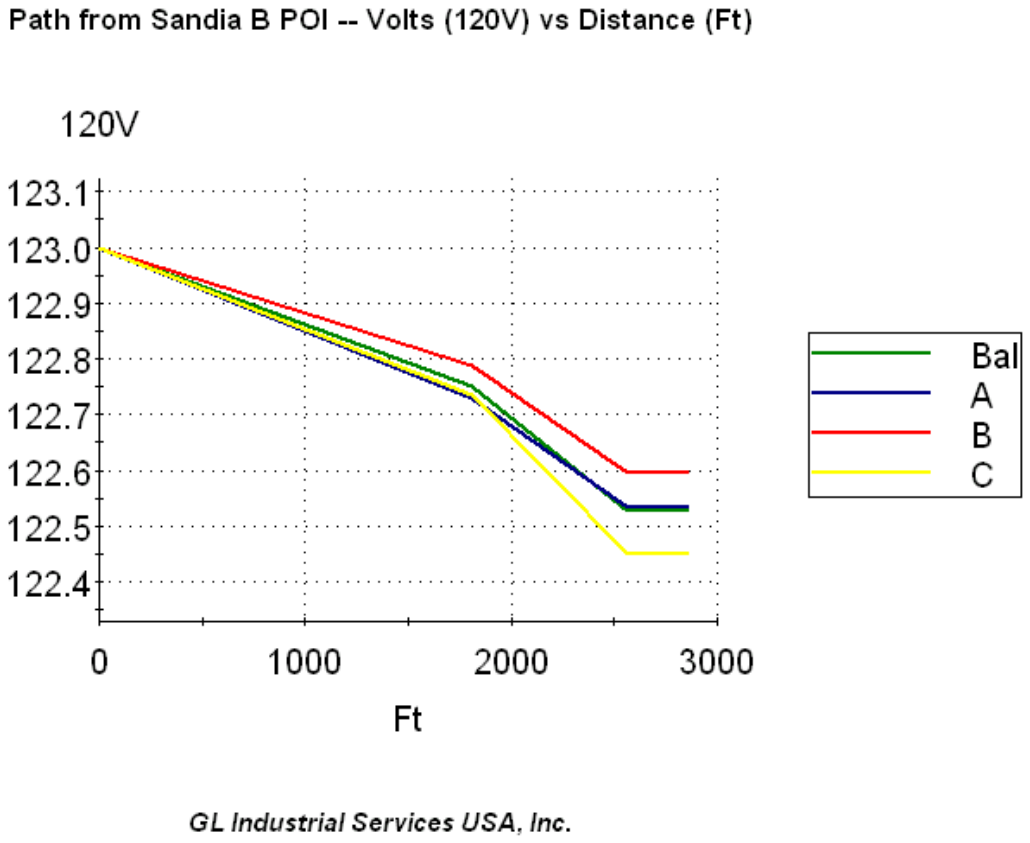
The voltages on Four Hills Feeder 12 for the loss of Innovation Substation after the installation of Project Sandia B are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.5.2 Contingency Configuration – Loss of Four Hills Substation, Peak Load

For the loss of the Four Hills Substation, 100% of the Four Hills Feeder 12 load is transferred to 100% of Innovation Feeder 13. Voltages for the modeled Innovation 13 and Four Hill 12 peak feeder loads for an Innovation Substation outage configuration are shown in Graphs 7 and 8.

Graph 7 shows the voltages without Sandia Project B and Graph 8 shows the voltages with the Sandia Project B in service. The circuit distance from Innovation Substation to the Project Sandia B POI is the same as was stated earlier for normal configuration.

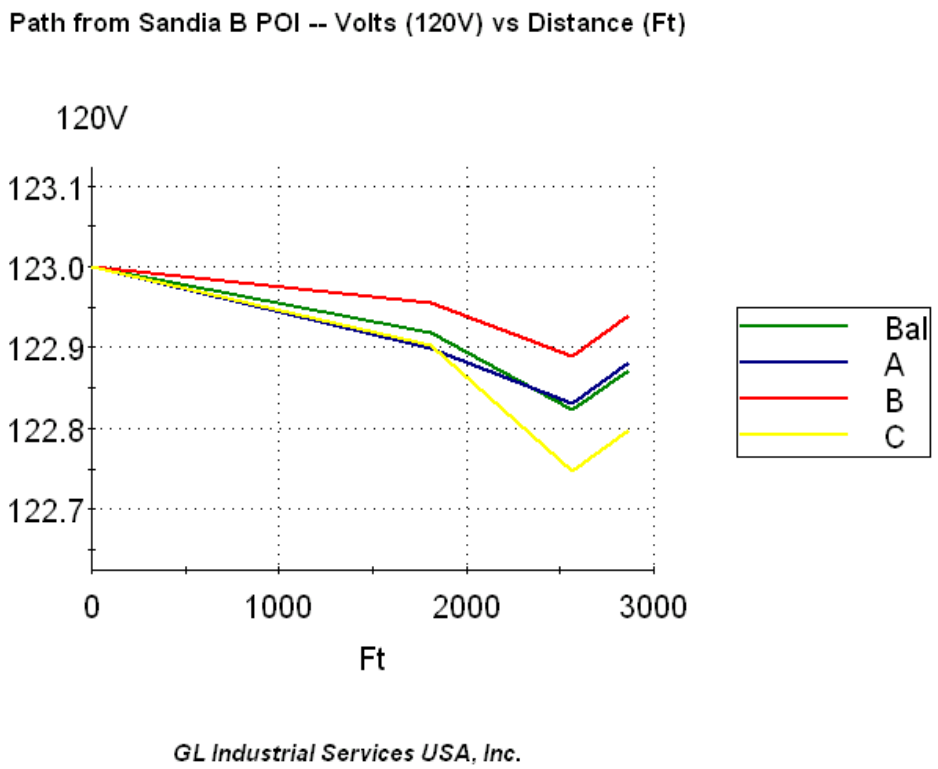
Graph 7 – Innovation Feeder 13 Voltage Profile From Innovation Substation to the Project Sandia B POI for the Loss of Four Hills Substation for Peak Daylight Hours Load. Project Sandia B is OFF.



The voltages at the point of interconnection are:
Phase A – 122.5 volts Phase B – 122.6 volts Phase C – 122.5 volts Balanced – 122.5 volts

The voltages on Innovation Feeder 13 for the loss of Four Hills Substation prior to the installation of Project Sandia B are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 8 – Innovation Feeder 13 Voltage Profile From Innovation Substation to the Project Sandia B POI for the Loss of Four Hills Substation for Peak Load. Project Sandia B is ON, 100% Power Factor.



The voltages at the point of interconnection are:
Phase A – 122.9 volts Phase B – 122.9 volts Phase C – 122.8 volts Balanced – 122.9 volts

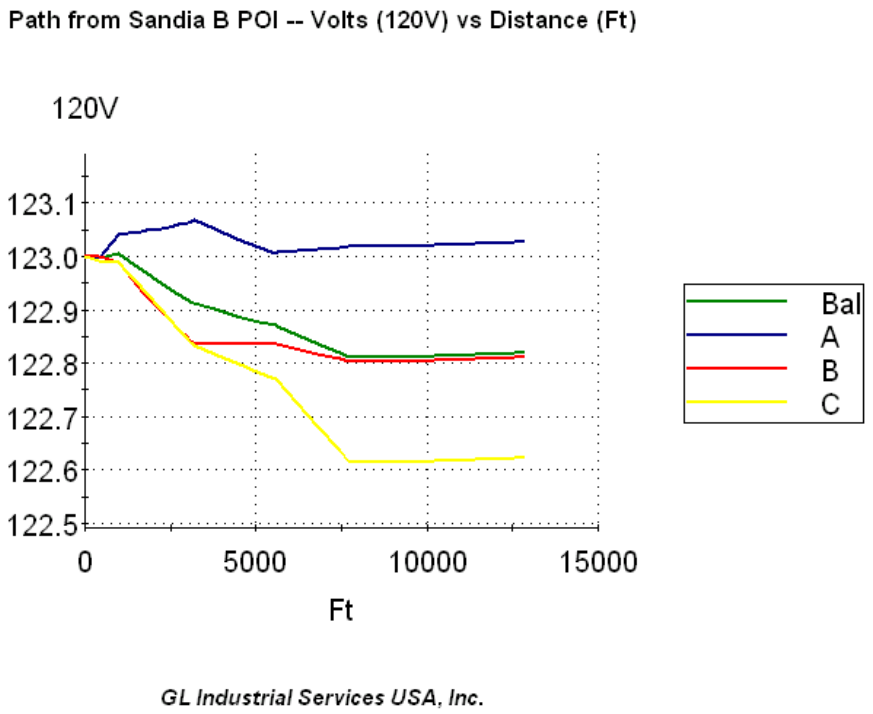
The voltages on Innovation Feeder 13 for the loss of Four Hills Substation after the installation of Project Sandia B are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.6 Voltage Impacts for Minimum Daylight Hours Load for Contingency Configuration

4.6.1 Contingency Configuration – Loss of Innovation Substation, Minimum Load

For the loss of the Innovation Substation, 100% of Innovation Feeder 13 load is transferred to Four Hills Substation through 100% of Four Hills Feeder 12. Voltages for the minimum feeder loads during daylight hours for an outage of Innovation Substation, with and without Project Sandia B are shown in Graphs 9 and 10.

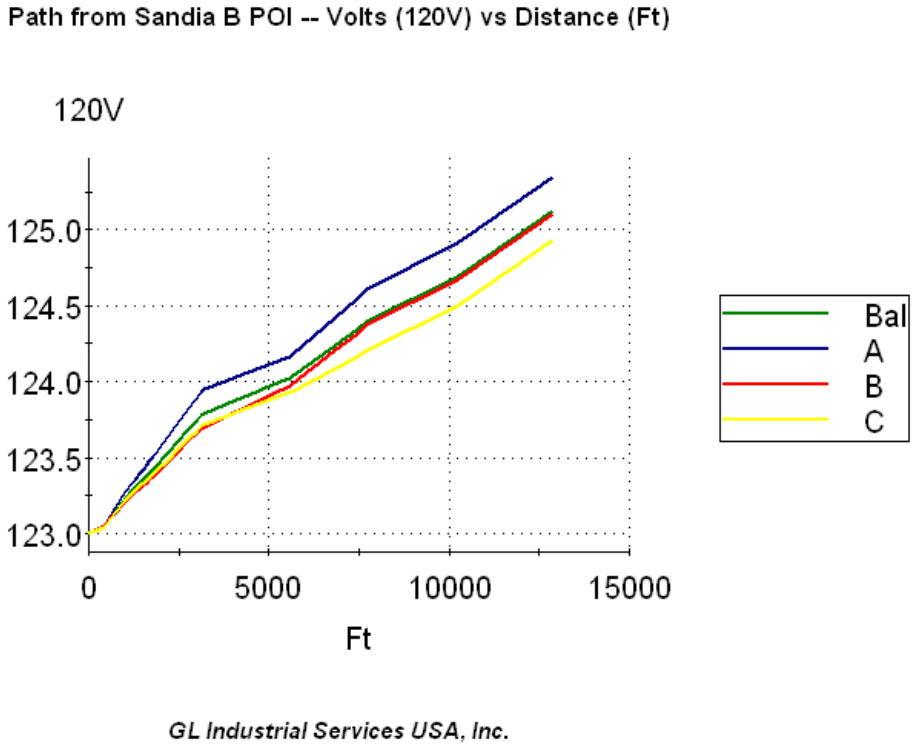
Graph 9 – Four Hills Feeder 12 Voltage Profile From Four Hills Substation to the Project Sandia B POI for the Loss of Innovation Substation for Minimum Load. Project Sandia B is OFF.



The voltages at the point of interconnection are:
Phase A – 123.0 volts Phase B – 122.8 volts Phase C – 122.6 volts Balanced – 122.8 volts.

The voltages on Four Hills Feeder 14 for the loss of Innovation Substation contingency prior to the installation of Project Sandia B are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 10 – Four Hills Feeder 12 Voltage Profile From Four Hills Substation to the Project Sandia B POI for the Loss of Innovation Substation for Minimum Load. Project Sandia B is ON, 100% power factor.



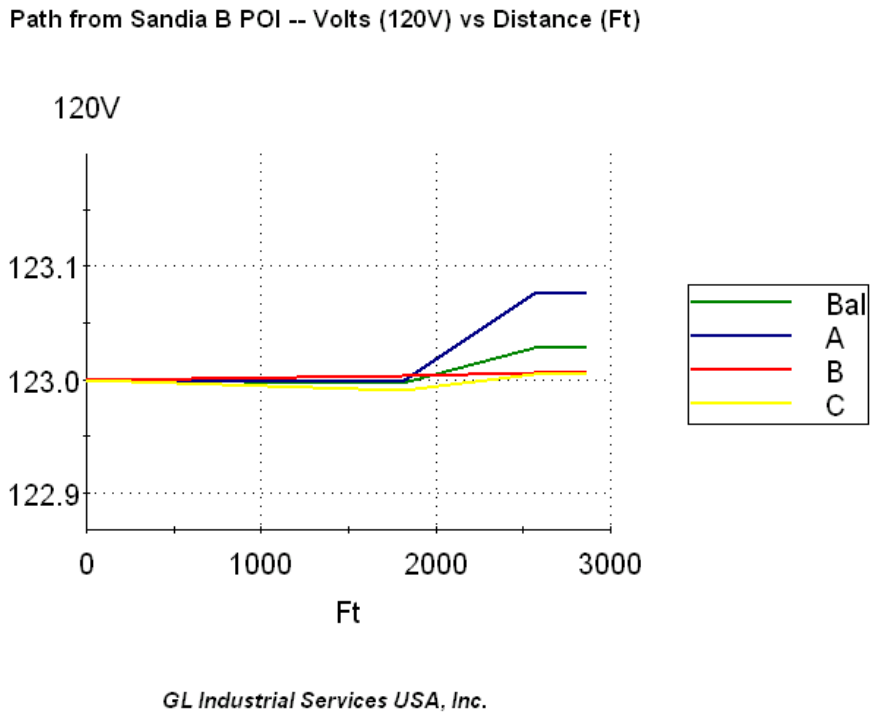
The model voltages at the point of interconnection are:
Phase A – 125.3 volts Phase B – 125.1 volts Phase C – 124.9 volts Balanced – 125.1 volts

The voltages on Four Hills Feeder 12 for the loss of Innovation Substation contingency after the installation of Project Sandia B are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.6.2 Contingency configuration – Loss of Four Hills Substation, Minimum Load

For the loss of the Four Hills Substation, 100% of Four Hills Feeder 12 is transferred to 100% of Innovation Feeder 13. Voltages for the feeder daylight hours minimum loads on Innovation 13 and Four Hills 12, with and without Project Sandia B, are shown in Graphs 11 and 12. The circuit distance from Innovation Substation to the Project Sandia B POI is the same as was stated earlier for normal configuration.

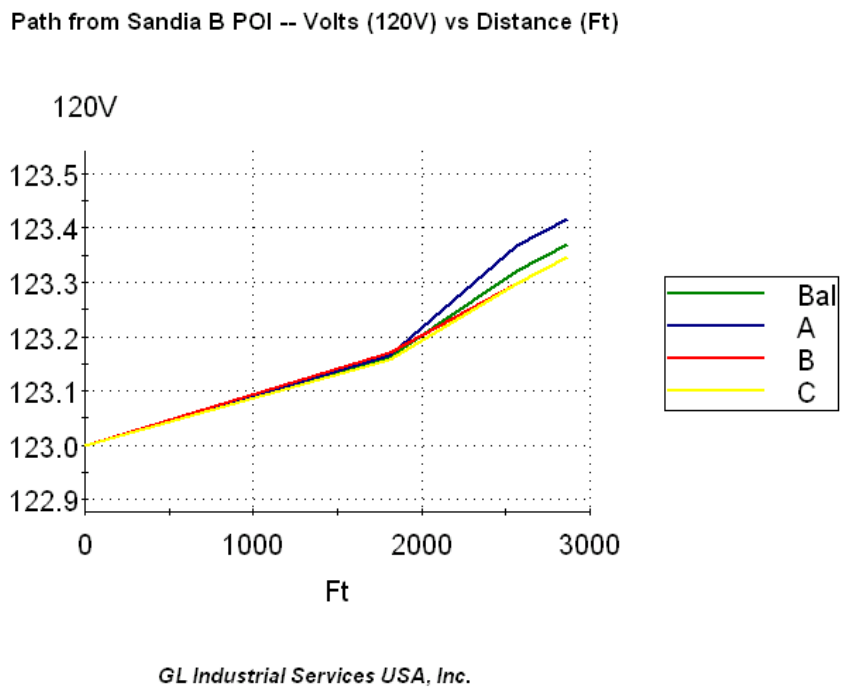
Graph 11 – Innovation Feeder 13 Voltage Profile from Innovation Substation to the Project Sandia B POI for the Loss of Four Hills Substation for Minimum Load. Project Sandia B is OFF.



The voltages at the point of interconnection are:
Phase A – 123.1 volts Phase B – 123.0 volts Phase C – 123.0 volts Balanced – 123.0volts

The voltages on Innovation Feeder 13 for the loss of Four Hills Substation contingency prior to the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 12 – Innovation Feeder 13 Voltage Profile from Innovation Substation to the Project Sandia B POI for the Loss of Four Hills Substation for Minimum Load. Project Sandia B is ON, 100% Power Factor.



The voltages at the point of interconnection are:
Phase A – 123.4 volts Phase B – 123.3 volts Phase C – 123.3 volts Balanced – 123.4 volts

The voltages on Innovation Feeder 13 for the loss of Four Hills Substation contingency after the installation of Project Sandia D are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In summary, although the output from Project Sandia B does cause the voltage on Innovation Feeder 13 and on Four Hills Feeder 12 to increase during contingency condition configurations, the voltages on both feeders remain within the PNM voltage criteria limits of ANSI C84.1 and are acceptable.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is accomplished by a combination of either of two methods. The first method is to employ a step voltage regulator located at either the substation or some distance from the substation along the feeder route. The second commonly employed method of voltage control on distribution feeders is the use of shunt capacitors installed along

the feeder route. The impact of the Project Sandia B on capacitor voltage control is discussed in Section 8 Capacitors.

The voltage regulation by a step voltage regulator can be accomplished by using either a load tap changer (LTC) on the substation transformer or by installing a voltage regulator out on the distribution feeder.

Project Sandia B is normally served by Innovation Feeder 13. The backup, or alternate source, for Innovation 13 during contingencies is Four Hills Feeder 12. There are no voltage regulators on either Innovation 13 or Four Hills 12. However, both Innovation and Four Hills substations employ an LTC to regulate the voltage at the substation 12.47kV bus. The Innovation Substation LTC is set at to regulate at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

Project Sandia B was modeled as a 5,000kVA source on Innovation Substation connected to Innovation Feeder 13 approximately 2,500 feet from the substation. The SynerGEE model for evaluating the impact of Project Sandia B on the Innovation Substation LTC included the Innovation Substation transformer and Innovation Feeders 11, 12 and 13. The SynerGEE model also included the previously studied 1MW DG1 PV plant that will be connected to Innovation Feeder 11 and the 1MW DG2 and 5,000kVA Sandia D PV generating plants that will be connected to Innovation Feeder 12. The substation bus voltage and load tap changer position results from the SynerGEE model for maximum daylight hours feeder loads for 2009 with DG1, DG2 and Sandia Project D operating and for the conditions of the 5,000kVA Project Sandia B Project operating and not operating, are shown in Tables 7, 8, 9 and 10.

As seen in Tables 7 – 10, the SynerGEE modeling shows the LTC did not change positions for 5,000kVA Project Sandia B resource source on the feeder for either high or low load periods.

Table 7 – Innovation Substation with Project Sandia B OFF for Peak Load

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.7	121.5	121.7	121.6
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 7. The voltages at Innovation Substation prior to the installation of Project Sandia B are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

Table 8 – Innovation Substation with Project Sandia B ON, 100% Power Factor For Peak Load

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	121.8	121.6	121.8	121.7
LTC position	Neutral	Neutral	Neutral	

The model voltages at the substation bus are shown in Table 8. The voltages at Innovation Substation after the installation of Project Sandia B are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The Innovation Substation bus voltages for the feeder minimum daylight hours load for 2009 with and without Project Sandia B, per the SynerGEE model, are shown in Tables 9 and 10.

Table 9 – Innovation Substation with Project Sandia B OFF For Minimum Load

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.6	122.31	122.5	122.5
LTC position	Neutral	Neutral	Neutral	

The voltages at Innovation Substation prior to the installation of Project Sandia B are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

The model voltage results at the substation bus with Project Sandia B in service during minimum loads are shown in Table 10.

Table 10 – Innovation Substation with Project Sandia B ON, 100% Power Factor For Minimum Load

	INNOVATION SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	122.6	122.4	122.6	122.5
LTC position	Neutral	Neutral	Neutral	

The voltages at Innovation Substation during minimum load conditions after the installation of Project Sandia B are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

In conclusion, the voltage on Innovation Substation bus stayed within the PNM criteria of ANSI C84.1 for both peak and minimum load conditions regardless of Project Sandia B output. There is a small variation in the voltages with Sandia B Project producing power versus the voltage without the Sandia B Project. These voltage variations might be significant enough to trigger an operation of the tap changer to operate. However, the output of the Project Sandia B is deemed to not have an adverse impact on the Innovation Substation LTC or bus system voltage regulation.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus borderline of visibility and borderline of irritation. PNM's operating criteria are that the magnitude of voltage flicker must be limited to less than 6% and that the frequency of flicker fluctuations be less than the border line of irritation boundary shown in the GE Flicker Limit Curve.[1]

Clouds shading the PV panels adversely impact the output of a PV system. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting.

[1] *Electric Utility Engineering Reference Book, vol. 3: Distribution Systems*. Trafford, PA: Westinghouse Electric Corporation, 1965.

A rapid change in load cannot be compensated by the voltage regulation equipment installed on a distribution system. The PNM has a time delay setting of 30 seconds for its substation LTCs and line voltage regulators. This time delay means that an LTC or voltage regulator will not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the duration of a voltage dip due to the starting of an electric motor.

The voltage at the Innovation Substation bus was fixed at 123 volts with and without Project Sandia B output for maximum and minimum load periods. Table 11 summarizes the balanced voltage and the calculated voltage flicker magnitude. Table 12 is based on an interpolation of the flicker frequency from the GE flicker graph.

Project output will exhibit relatively slow variations due to cloud cover shading rather than spike between full on and off. Consequently the results shown in Table 11 represent a worst-case scenario. For a 0.33% flicker magnitude the frequency of voltages fluctuations would need to be on the order of 6 fluctuations per second to approach the borderline of irritation limit. Cloud movement is slow thus voltage flicker frequency of fluctuations will be less than the frequency limits shown in Table 12. The calculated magnitude of the flicker due to the Sandia B Project is much less than PNM's 6% limit criterion. The distribution voltage flicker resulting from changes in Project Sandia B output is not anticipated to have an adverse effect.

Table 11 – Voltage Flicker Magnitude at POI Due to Project Sandia B

	Project Sandia B POI Voltage	
	Minimum Load on Innovation 13	**Maximum Load On Innovation 13**
Without Project	123.0	122.8
With Project	123.4	123.1
% Voltage Flicker	**0.33**	**0.24**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 12 – Frequency of Flicker Fluctuations Due to PV Output Changes

% Voltage Flicker	Based on GE Flicker curve	
	Border Line of Visibility	Border Line of Irritation
0.33	6/sec	No Irritation
0.24	10/sec	No Irritation

7.0 LINE SEGMENT CONDUCTOR LOADING

Project Sandia B will be connected to Innovation Substation Feeder 13 that has not been constructed at the time of this study. Standard PNM feeder underground and overhead conductor sizes and construction types were modeled for the new Innovation 13 substation get-a-way and for the overhead line planned for connecting the new feeder to the existing PNM distribution system. Conductor loadings from the Project Sandia B POI to the substation were reviewed using the SynerGEE feeder model with and without Project Sandia B's maximum output of 5,000 kW.

There were no conductor loading problems between the POI and the substation on Innovation Feeder 13 with or without Project Sandia B.

8.0 CAPACITORS

Shunt capacitors are used on utility distribution systems for Volt Amperes Reactive (VAR) and voltage control. PNM employees a combination of fixed and switchable capacitor banks on its distribution system. On the PNM distribution system switched capacitor banks are remotely controlled by a Radio Control Central Station (RCCS) system. The RCCS system polls PNM's System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size. Fixed capacitor banks remain in service all the time but may be switched off seasonally by manual methods.

An inverter based grid connection will be a real power source for the distribution system, which when operating at 100% power factor, delivers watts only, no VARs. Consequently, when the inverter is operating the power factor of the distribution feeder will appear to become worse.

There are no RCCS controlled capacitors currently install on either Innovation Feeder 13 or on its backup feeder Four Hills Feeder 12. Innovation 13 has one 600kVAR fixed capacitor and Four Hills 12 has two 600kVAR fixed capacitors. Table 13 summarizes the impact of the presence of Project Sandia B's 5,000kVA of generation at unity power factor during peak and minimum feeder load conditions

Table 13 – Innovation 13 Power Factor for Normal Configurations

Feeder	Load	Generator Status	Power Factor (%)
Innovation 13	Peak	Off	98
Innovation 13	Peak	On	97
Innovation 13	Minimum	Off	73
Innovation 13	Minimum	On	99

As expected the addition of the Project Sandia B to Innovation 13 at unity power factor during peak load periods results in a decrease in the feeder's power factor as measured at the substation. During periods of minimum load on Innovation 13 the presence of the Project Sandia B's generation at unity results in an increase in the feeder's power factor as measured at the substation.

The impact of the presence of Project Sandia B's 5,000kVA of generation at unity power factor on feeder power factors for an outage of either Innovation Feeder 13 or Four Hills Feeder 12 during both peak and minimum load conditions was as studied. Table 14 summarizes the impact of Project Sandia B on feeder power factor for outages of Innovation 13 and Four Hills 12 during peak and minimum load conditions.

Table 14 – Impact of Sandia B on Power Factor for Contingency Configurations

Feeder Outage	Load	Generator Status	Backup Feeder	Power Factor (%)
Innovation 13	Peak	Off	Four Hills 12	99
Innovation 13	Peak	On	Four Hills 12	73
Innovation 13	Minimum	Off	Four Hills 12	67
Innovation 13	Minimum	On	Four Hills 12	91
Four Hills 12	Peak	Off	Innovation 13	99
Four Hills 12	Peak	On	Innovation 13	70
Four Hills 12	Minimum	Off	Innovation 13	67
Four Hills 12	Minimum	On	Innovation 13	90

As expected for contingency configurations during peak load periods, the production of Project Sandia B at unity power results in a decrease in the power factor measured at the substation.

During periods of minimum load the presence of the Project Sandia B's generation at unity power factor results in an increase in the feeder's power factor as measured at the substation.

During peak load periods, for both normal and contingency configurations, reactive power is being absorbed from the substation by the feeder regardless of the power produced by the Project at unity power factor. During minimum load periods, for both normal and contingency configurations, reactive power is being exported to the substation by the feeder regardless of the power being produced by the Project at unity power factor.

For peak and minimum load conditions and with the fixed capacitors on both Innovation 13 and Four Hills 12 in service, the voltages on both circuits, without and with Project Sandia B are within PNM's ANSI C84.1 operating criteria for normal and contingency configurations.

9.0 PROTECTION

9.1 Normal Configuration – Service from Innovation Feeder 13

Innovation Substation Feeder 13 is protected from overcurrents by a 1,200 amp breaker in metal clad switchgear. An ABB DPU2000R relay provides phase overcurrent and residual ground overcurrent detection as well as recloser timing intervals. An additional DPU 2000R relay provides switchgear bus and feeder backup protection. Protection for the Innovation Substation transformer is provided by an ABB TPU2000R differential relay.

Fault analyses were conducted for the normal service configuration of Innovation Feeder 13 to determine the impact of Project Sandia B's interconnection on feeder's protective devices. The SGIR applicant specified that each inverter would provide 4,300 Amperes of fault current at 200V. As noted on the SGIR application form, the Sandia B interconnection transformer is a 480V Wye-grounded to 12.47kV Wye-grounded transformer. An ideal transformer with a turns ratio of 200:480 was used to transform the fault current at 200V provided by the applicant to a value at 480V for fault analysis modeling. Project Sandia B was modeled as a connection to the distribution primary system approximately 2,500 circuit feet from Innovation Substation on Innovation Substation Feeder 13. There are no reclosers or sectionalizers installed on Innovation 13.

The fault analysis first considered end of circuit faults. Generation installed between a recloser or substation breaker and the location of a fault masks a portion of the fault current from the upstream protective device. The effect of this masking is to desensitize the protective device. With no reclosers on Innovation 13 an end of line fault presents the greatest potential for desensitizing the substation breaker relay and preventing the relay from detecting the fault. The fault analysis shows that the fault contribution of Project Sandia B will not interfere with the proper operation of the substation relay and breaker for an end of circuit fault when the feeder is in its normal configuration.

The impact of Project Sandia B's fault contribution to fuse coordination was also evaluated. The fault analysis shows that the fault contribution of Project Sandia B will not interfere with the proper coordination between the installed tap line fuses and the substation relay.

The fault analyses also evaluated the impact of Project Sandia B on faults close to the substation breaker. For faults close to the substation bus, the generator's fault current contribution could cause the substation feeder breaker to open for faults on the substation bus or for faults close to the substation on adjacent feeders. An unintended feeder breaker operation for a bus fault or for a fault on an adjacent feeder is considered to be a miscoordination of the feeder's breaker and relay device protective scheme. Fault analysis shows that that the fault current contribution from Project Sandia B is less than the minimum pickup current value for the Innovation 13 relay for faults close to the substation. Project Sandia B will not cause a mis-operation of the substation feeder breaker for faults close to the substation.

The analysis of faults close to Innovation Substation shows that Project Sandia B as modeled will not cause the fault current to exceed 10,000A for faults. Fault analysis showed that no equipment fault duty ratings were exceeded.

Project Sandia B as modeled does not require any system protection improvements to be made to the Innovation Substation Feeder 13 under normal configuration to correct coordination problems.

9.2 Contingency Configuration – Innovation Feeder 13 Picks Up Fours Hills Feeder 12 for an Outage of Four Hills Substation

For an outage of Four Hills Substation, Innovation Feeder 13 picks up all of the Four Hills Feeder 12 circuit. Fault analyses were completed to evaluate the impact of Project Sandia B on Innovation 13's ability to detect and interrupt faults while simultaneously serving both feeders.

Project Sandia B was modeled in SynerGEE to produce the 1,792 Amperes of fault current at 480V (4,300A at 200V) for each 500kVA inverter. The SynerGEE model of the 5,000kVA Sandia Project B PV plant provided a total of 17,917A of fault current at 480V for the fault analyses.

The fault analyses show that with Sandia Project B connected, Innovation 13 will be able to adequately detect end of circuit faults on Four Hills 12 and that adequate relay-fuse coordination is maintained and that no equipment fault duty ratings were exceeded.

Project Sandia B does not cause adverse equipment or protective device impacts for a Four Hills Substation outage.

9.3 Contingency Configuration – Four Hills Feeder 12 picks up Innovation Feeder 13 for an outage of Innovation Substation

Four Hills Feeder 12 is protected by a 1,200 amp breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay to provide reclose interval timing. Protection for the switchgear bus and feeder backup protection is provided by three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. Protection for the Four Hills Substation transformer is provided by three Westinghouse, CA differential relays.

For an outage of Innovation Substation, Four Hills Feeder 12 will pick up all of the Innovation Feeder 13 circuit. Fault analyses were completed to evaluate the impact of Project Sandia B on Four Hills Feeder 12's ability to detect and interrupt faults while simultaneously serving both feeders.

Project Sandia B will be connected to the distribution primary system approximately 2.86 miles from Four Hills Substation. There are no reclosers or sectionalizers on either Four Hills Feeder 12 or on Innovation Feeder 13. The fault analyses considered end of circuit faults, relay-fuse coordination, faults close to Four Hills Substation and equipment ratings.

The fault analyses show that with Sandia Project B connected, Four Hills 12 will be able to adequately detect end of circuit faults on Innovation and that adequate relay-fuse coordination is maintained and that no equipment fault duty ratings were exceeded.

Project Sandia B does not cause adverse equipment or protective device impacts for an Innovation Substation outage.

10.0 FEEDER LOADING

The impact of Project Sandia B's power production on the feeder loading during peak and minimum load periods was evaluated for both Innovation Feeder 13 and its backup feeder, Four Hills Feeder 12.

Project Sandia B output exceeds the modeled maximum and minimum loads on both Innovation Feeder 13 and Four Hills Feeder 12 during daylight hours. For the modeled loads and for the assumed conductors to be used for the future construction of Innovation Feeder 13, no equipment overloads were identified no equipment overloads were identified on Innovation

Feeder 13. In its current configuration and for the loads modeled, no equipment overloads were identified on Four Hills Feeder 12.

11.0 METERING and COMMUNICATION

PNM metering and communication equipment will be located on the Project site within an easement provided by the Project owner. For redundancy, two revenue quality meters with associated potential and current transformers will be installed. Communication equipment that will allow PNM to access and down load data from the meters into PNM's data collection system as well as monitor the Project status will also be installed and located at the metering point. The meter information will be used for both billing and project status monitoring purposes. The project status data will be used to determine Project instantaneous and historic KW and KWH output.

The following cost estimates for communication have been developed:

ONE-TIME Equipment COST	$ 35,000
One-Time Labor Cost	$ 10,000
MONTHLY Recurring O&M	$ 3,500

The breakdown of the ONE-TIME Equipment cost:

Satellite or TELCO PRIMARY Installation	$ 5,000
Microwave or other backup Install	$ 20,000
Channel Bank Equipment	$ 10,000

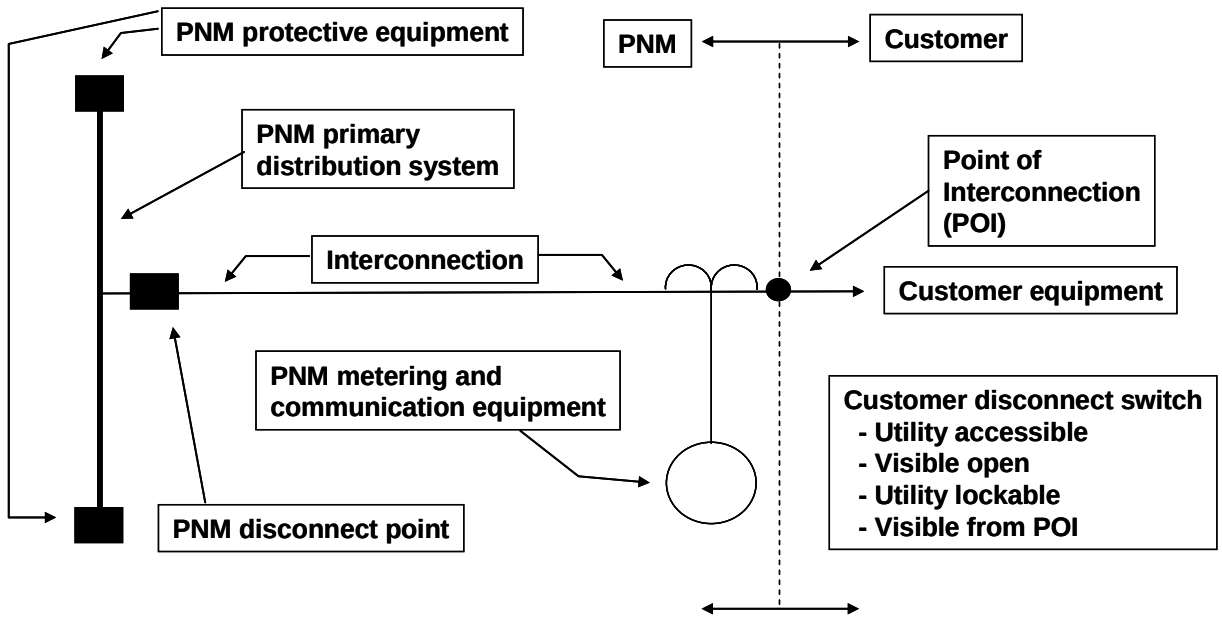
12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is a one-line diagram of the typical configuration of a generator connected to the PNM distribution primary system. Figure 3 is intended for illustration purposes only and is not intended to imply either approval for or recommendations for the design of any specific project.

The PNM disconnect point shown in Figure 3 will consist of a remotely controlled switch. The switch will allow PNM's Distribution Operations Center to continuously monitor the status of the Project's output and to remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The PNM disconnect point switch may also provide protection for the PNM system.

Figure 3 – Typical Project Interconnection

Typical connection of a Photovoltaic system to the PNM distribution system

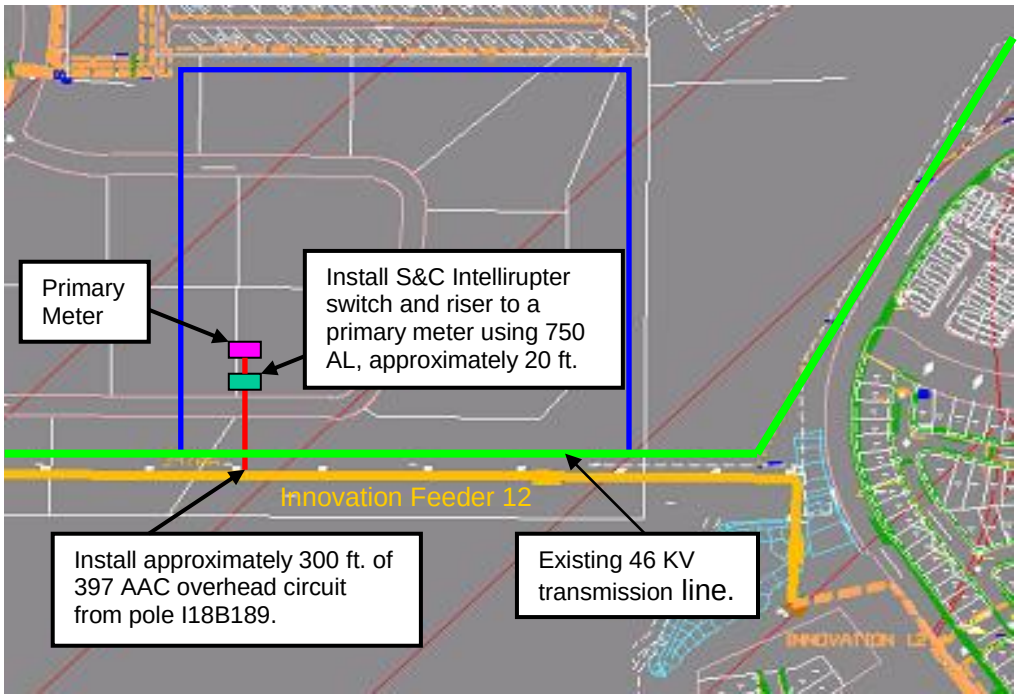


13.0 INTERCONNECTION RELATED COSTS

To connect Project Sandia B to the PNM distribution system, a 12.47kV feeder line extension is required. The interconnection feeder line extension consists of:

- Approximately 300 ft. of new 397 AAC overhead circuit from pole I18B189 to the PV site location. This extension will cross under an existing 46 kV transmission line. Any modifications to the 46 kV line are included in the estimated costs. (See Figure 4).
- Install One S&C IntelliRupter switch (See Figure 4).
- Install one 750MCM CN AL riser to transition from the new overhead line to the PV primary meter location, approximately 20 feet. (See Figure 4)

<u>Figure 4</u> – Line Extension to connect Project Sandia B to Innovation Feeder 13



The preliminary estimated costs in 2011 dollars to interconnect the Sandia Project B facility to the PNM distribution primary are shown in Table 15.

In addition to the interconnection costs listed in Table 15, Project Sandia B will be required to install, own and maintain a three-phase, load-break, lockable switching device between PNM's primary meter and the Project Sandia B facilities. This switching device must be readily accessible to PNM personnel at all times to provide a lockable and visible means of disconnecting Project Sandia B from the primary meter. Provisions for PNM personnel to operate this PMH disconnecting device will be addressed in the interconnection and operating agreements between PNM and XXX.

Table 15 – Project Sandia D Interconnection Cost

	ESTIMATED COSTS (2011 Dollars)	Estimated Construction Time
PNM Disconnect Point Switch (Intellirupter)	$ 70,400	~26 Weeks lead time ~4 Days to build
Interconnection (Distribution Line Construction)	$ 24,580	~1 Week lead time ~7 Days to build
Raise 46kV Subtransmission Line	$ 75,000	~4 Weeks lead time ~3 Days to build
PNM Primary Metering	$ 26,000	~16 Weeks lead time ~3 Days to build
Communications	$ 45,000	~16 Week lead time ~3 Weeks to build
Protection	$0	
Rights-of-Way	$6,500	
Environmental	$12,200	
TOTAL	**$ 259,680**	**6-7 months for lead time and final build out**

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 FACILITY MAINTENANCE AND OPERATION AGREEMENTS

Facility operations in response to alarms associated with the PV array and inverter are the responsibility of the interconnector and to be defined in the network interconnection service agreement and network operating agreements (NOA).

16.0 CONCLUSIONS

The Project Sandia B will result in an interconnection with PNM's Innovation Substation Feeder 13 approximately 2,500 feet from Sandia Substation. Project Sandia B does not have an adverse impact on the PNM distribution system. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1 during peak and minimum load periods for both normal and contingency configurations. The presence of the Project did not exhibit an adverse impact on power factor. The analysis also shows that variation in the output of Project Sandia B will not cause voltage flicker problems for other customers on the distribution system. Analysis showed that the Project output did not cause conductor or feeder equipment ratings to be exceeded for unfaulted normal and contingency configurations. The automatic control of voltage by the substation LTC may cause the LTC to operate due to the presence of Project Sandia B, but this is not anticipated to be an adverse effect.

The Project Sandia B output alone will cause approximately 600kW to flow from the distribution system through the substation transformer on to the transmission system during minimum load periods. No transmission system voltage problems are anticipated as a result of this power flow from the distribution system to the transmission system. The output of Project Sandia B combined with the outputs of Project Sandia D, DG1 and DG2 will cause about 1,140kW to flow from the distribution system to the transmission system during peak load periods. During minimum load periods the power flow from the distribution system to the transmission increases to about 7,610kW. No transmission system voltage problems are anticipated as a result of either the 1,140kW or the 7,610kW of power flow from the distribution system to the transmission system.

The fault analyses show that with Sandia Project B connected faults can be adequately detected and that adequate relay-fuse coordination is maintained for both normal and contingency circuit configurations. The 3,500A fault current contribution per inverter listed in the SGIR application results in fault currents greater than 10,000A for faults near Innovation Substation. Project Sandia B's final design will have to show that the fault current contribution of the project will not cause the maximum fault current on the PNM 12.47kV distribution system to exceed 10,000A.

The result of evaluating the distribution primary system impacts associated with Project Sandia B is a determination that there are no adverse impacts associated with the interconnection of Project Sandia B's 5,000 KW resource to Innovation Substation or Innovation Feeder 13 if the

project is designed so that the Project does not cause maximum fault current on PNM's 12.47kV system to exceed 10,000A.

Distribution Planning has determined that system upgrades are not required to ensure that electric service to all customers on Innovation Substation is maintained within established PNM voltage, equipment and fault protection criteria.

PUBLIC SERVICE COMPANY OF NEW MEXICO
INTER-OFFICE CORRESPONDENCE

TO: Kathy Maddux – 0604
FROM: Paul Cote
DATE: October 15, 2010
SUBJECT: GPD DOE 500 KW PV Project Evaluation

Distribution Planning received an evaluation request for the installation of an inverter based grid connected photovoltaic system nominally rated at 500 KW AC identified as GPD DOE 500 KW PV.

The 'Open Access Transmission Tariff of Public Service Company of New Mexico' dated January 14, 2010 Attachment M for 'Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less than 20 MW' Applicability Section 1.1.1 states that a certified Small Generating Facility no larger than 2 MW shall be evaluated under the Section 2 Fast Track Process. Distribution Planning's review of this Project is based on the Fast Track Process 10 steps – see Attachment 1. The results of the review are shown in Table 1.

The GPD DOE 500 KW PV project proposed location is at the intersection of Bobby Foster Rd SE and Los Picaros Rd SE within the proposed Prosperity Station property in the Albuquerque Division – See Figure 1. The location will result in a connection to Sewer Plant Feeder 14.

FIGURE 1

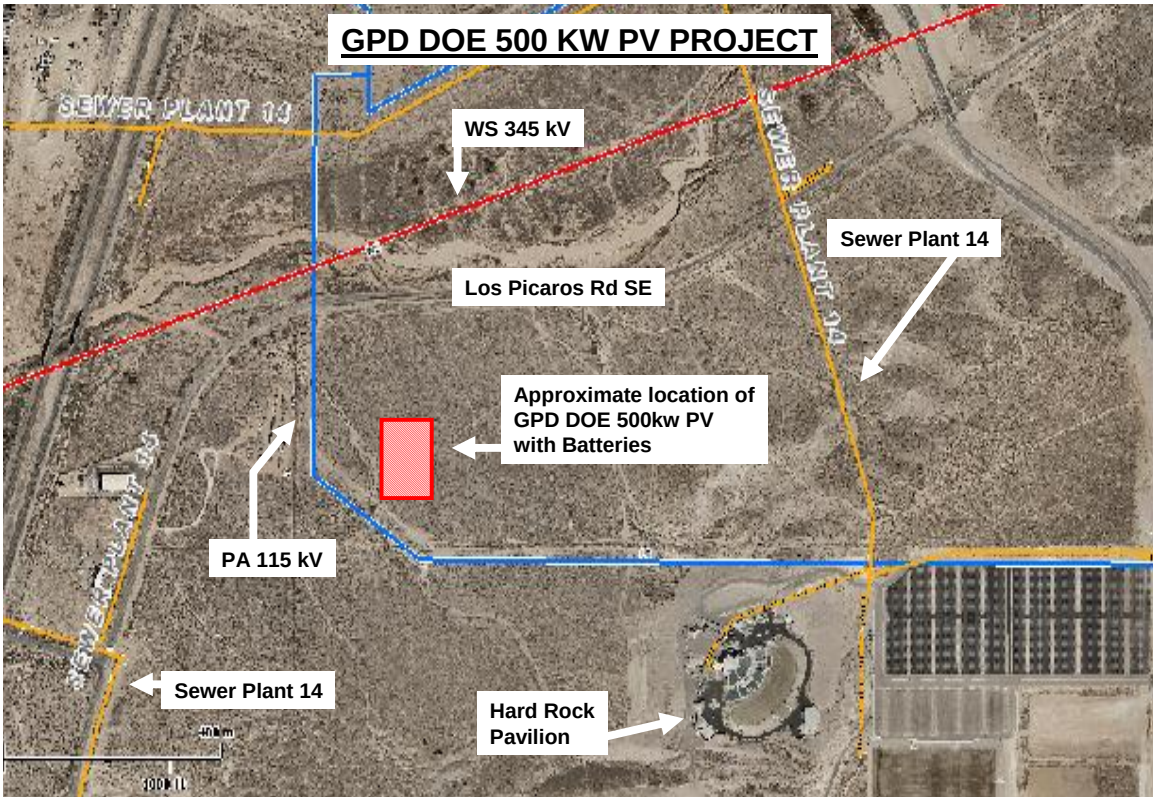


TABLE 1

GPD DOE 500 KW PV – Screening results table per SGIP

Screen section 2.2.1	Result	Comment
2.2.1.1	Applicable	
2.2.1.2	Passed	Sewer Plant 14 2009 July peak load was 5.6 MVA. Per the Synergee model the line section of probable interconnection had a power flow amount of about 732 KVA. Thus, 15% of the flow is 110 KVA, which is less than the proposed project size. Although the Project failed the Fast Track screening language Distribution Planning considers the Project acceptable.
2.2.1.3	Not Applicable	
2.2.1.4	Passed	The approx. symmetrical 3-phase fault current at the POI is about 1,611 amps – 10% would be 161 amps. The proposed project indicates a max fault current contribution of 87 amps at 12.47 kV. Project fault current is less than 10% limit at POI.
2.2.1.5	Passed	Assume an S&C Intelliruptor would be the PNM protective device at the POI. The aggregate generation does not exceed 87.5% or 8750 amps of this device interrupting capability.
2.2.1.6	Pass	
2.2.1.7	Not Applicable	
2.2.1.8	Not Applicable	
2.2.1.9	Pass	There is one PV installation on the feeder rated at 1.28 KW. The aggregate of the existing generation and the proposed project PV installation on the feeder is less than 10 MW.
2.2.1.10	Pass	Site is located at the existing Prosperity Station site. The nearest distribution circuit is Sewer Plant Feeder 14 3-phase line. Depending on easement acquisition a 3-phase overhead line to the PV facility will be 2,000 to 3,000 feet plus a short (150 ft) UG dip to the primary meter will be needed.

NOTE: This screening analysis is site specific and based on the PNM distribution primary system in the vicinity of the proposed project site.

The estimated cost of connecting the GPD DOE 500 KW PV Project to Sewer Plant Feeder 14 is summarized in Table 2.

TABLE 2

INTERCONNECTION COST ESTIMATE

	ESTIMATED COSTS 2010$	**ESTIMATED CONSTRUCTION TIME**
Overhead line extension	$ 196,000	20 weeks
Environmental	$ 29,500	
Primary meter	$ 19,000	
Right of Way	$ 9,000	
Communication	$ 45,000	
Communication monthly O&M	$ 3,500	
TOTAL	**$ 298,500** **Plus monthly O&M of $3,500**	20 weeks (5 months)

In conclusion, Distribution Planning has determined that the proposed GPD DOE 500 KW PV project connected to Sewer Plant Feeder 14 has minimal or no impact on the distribution system equipment loading and voltages. The distribution system impact associated with fault currents must still be determined.

Evaluation time for GPD DOE 500 KW PV was charged to:
002-253010 – 650 – D0000000 - D1860280

Do not hesitate to contact me at ext. 4572 or Manuel Sanchez at ext. 4566 if you have any questions.

Paul Cote
Distribution Planning
Professional Engineer

Distribution:

Rahn Petersen – 0600
Manuel Sanchez – 0604

ATTACHMENT 1

Excerpt from
'Open Access Transmission Tariff of Public Service Company of New Mexico'

ATTACHMENT M: Small Generator Interconnection Procedures (SGIP) For Generator Interconnections Less Than 20 MW

Section 2 Fast Track Process

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Transmission System if the Small Generating Facility is no larger than 2 MW and if the Interconnection Customer's proposed Small Generating Facility meets the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

2.2 Initial Review

Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens.

2.2.1 Screens

2.2.1.1

The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff.

2.2.1.2

For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3

For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 KW.

NOTE: A spot Network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. (Standard Handbook for Electrical Engineers, 11th edition, Donald Fink, McGraw Hill Book Company)

2.2.1.4

The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5

The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

2.2.1.6

Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

2.2.1.7

If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8

If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

2.2.1.9

The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10

No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.