ERAS-2025-001 – INTERCONNECTION FACILITY STUDY (IFS)

Lincoln Electric System

APRIL 2026

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Executive Summary

Lincoln Electric System (LES), as a Transmission Owner (TO) and Transmission Planner (TP), was tasked with completing an Interconnection Facility Study (IFS) by the Southwest Power Pool (SPP) in accordance with SPP Open Access Transmission Tariff, Sixth Revised Volume No.1, Attachment AW: Expedited Resource Adequacy Study (ERAS), Sections 8.10 and 8.11.

LES as an Interconnection Customer (IC) submitted an ERAS application to SPP to interconnect new generation on the LES transmission system by expanding the Terry Bundy Generating Station (TBGS). The 84th and Bluff Substation will serve as the Point of Interconnection, with the IC requesting a maximum injection total of 104 MW. The IC's ERAS application includes the following two generation units:

- TBGS#5 → LM6000 gas turbine with 52MW of max injection
- TBGS#6 → LM6000 gas turbine with 52MW of max injection

Steady-state and short-circuit analyses were conducted by SPP prior to sending an IFS request to LES. SPP identified no steady-state or short-circuit violations following the addition of the IC's requested generation to the LES transmission system. LES reviewed these results and found SPP's steady-state and short-circuit analyses satisfactory, so LES accepted these study results for its IFS.

This report documents all relevant information pertaining to the new generator interconnections at TBGS including dynamic analyses which exhibited stablity, positive damping, and acceptable transient voltages. The interconnection of new generation resulted in no adverse impacts on the LES transmission system and all dynamic criteria is within acceptable limits in both pre- and post-contingency conditions, satisfying the NERC FAC-002-4 standard.

To accommadate this interconnection a new Phasor Measuring Unit (PMU) will be required at the 84th & Bluff Substation. LES estimates that it will cost $44,275.00 to install this new PMU with a lead time of 24 months.

Introduction

Lincoln Electric System (LES), as a Transmission Owner (TO) and Transmission Planner (TP), was tasked with completing an Interconnection Facility Study (IFS) by the Southwest Power Pool (SPP) in accordance with SPP Open Access Transmission Tariff (OATT), Sixth Revised Volume No.1, Attachment AW: Expedited Resource Adequacy Study (ERAS), Sections 8.10 and 8.11.

LES as an Interconnection Customer (IC) submitted an ERAS application to SPP to interconnect new generation on the LES transmission system by expanding the Terry Bundy Generating Station (TBGS). The 84th and Bluff Substation (S75) will serve as the Point of Interconnection, with the IC requesting a maximum injection total of 104 MW. The IC's ERAS application includes the following two generation units:

- TBGS#5 → LM6000 gas turbine with 52MW of max injection
- TBGS#6 → LM6000 gas turbine with 52MW of max injection

This generator interconnection request is being studied under the NERC Facility Interconnection Studies (FAC-002-4) standard due to an IC seeking to make a qualified change to LES's existing portion of the Bulk Electric System via new generation facilities.

Steady-State and Short-Circuit Analysis Deferment

FAC-002-4 R1.3 states that steady-state, short-circuit, and dynamics studies shall be studied as necessary. LES will defer the steady-state and short-circuit portion of the FAC-002 requirement to SPP's ERAS-2025-001 study results, completed prior to this IFS.

SPP currently runs steady-state analysis of all generation interconnection requests on the SPP system, prior to submitting an IFS request to the TO. As a member of SPP, LES provides all of its contingencies to SPP annually per SPP's request for contingencies. SPP runs steady-state analysis utilizing these and all other member submitted contingencies when evaluating generator interconnection requests. These results lead to the determination of reliability driven Directly Assigned Upgrade Costs for SPP generation interconnection requests. Completing an additional steady-state analysis with the same contingencies for expansion of TBGS was considered redundant and unnecessary by LES engineering judgement.

SPP performed a short-circuit screening and analysis per SPP Business Practice 7250 (indicated in SPP OATT Attachment AW Section 6.2 and 6.3) prior to submitting an IFS request to the TO. Upon review of SPP's results, an additional short-circuit analysis was considered redundant and unnecessary by LES engineering judgement.

Study Assumptions

The dynamic analysis utilized both the 2030 Summer Peak case and Spring Light Load cases, from the SPP Model Development Advisory Group (MDAG) 2025 Series dynamics package, the most current set of finalized dynamic models posted by SPP at the time this study was performed. The year 2030 cases were chosen due to being the best seasonal representations to accommodate the IC's requested Commercial Operation date of 6/1/2029.

Prior to this study, General Electric (GE) provided the IC with up-to-date LM6000 models. The IC then provided these models to the TP. The LM6000 models are limited by a turbine rating of 46.6 MW. To appropriately test the provided model and maximum injection of the IC's request, LES completed dynamic analyses at both the 46.6 MW and 52 MW dispatch levels. General model and generation dispatch information is shown in Table 1 below. Full dynamic model information is provided in Appendix A.

ERAS Generation Dispatch					
ERAS Generator	**Turbine Pmax (MW)**	**Project Pmax (MW)**	**Generator Model**	**Excitation Model**	**Governor Model**
TBGS5	46.6	52	GENROU	AC7B	GGOV1
TBGS6	46.6	52	GENROU	AC7B	GGOV1
Total Gen Dispatch	**Turbine Pmax: 93.2 MW**			**Project Pmax: 104 MW**	

Table 1: ERAS Generation Dispatch

Study Criteria

This study adheres to the NERC Reliability Standards, specifically NERC FAC-002-4, the SPP Planning Criteria, SPP Zone 16 Zonal Planning Criteria (ZPC), and the LES Facility Interconnection Requirements (LES Requirements for System Interconnections to Generations, Transmission, and End-User Facilities).

Transient Stability and Voltage Criteria
LES adheres to the SPP Disturbance Performance Requirements (Appendix B). This criterion specifies both the Rotor Angle Damping and Transient Voltage Recovery requirements for dynamic analysis.

Alternatives Considered

SPP OATT Attachment AW Section 3.4 specifies the only alternatives a TO can consider when reviewing the IC's generator request, at the IC's option, are the project's POI and configuration during a scoping meeting. LES had no issues with the requested POI or configuration. No other alternatives were considered.

Coordination

The LES Resource & Transmission Planning (R&T) department, serving as the TP, coordinated this interconnection request at S75 via TBGS with SPP as the Planning Coordinator for LES throughout the SPP ERAS process. R&T coordinated with the LES Energy Delivery division, serving as the TO, to receive the most up-to-date information for substation one-lines, scope of interconnection projects, cost estimates, lead times, and necessity of short-circuit analysis.

Dynamic Analysis

The PSS/E Power System Simulator, version 35.6.0, was used for dynamic analysis of the near-term planning horizon and was conducted using the SPP MDAG 2030 (Year 5) Summer peak and Spring Light Load dynamic cases. These cases were selected from the library of cases included in the SPP 2025 MDAG Series Models, the most current set of finalized models at the time this study was performed.

The two proposed generation units were modeled on PSS/E bus 650277. This bus then has a generation tie-line that connects directly to the POI (PSS/E bus 650275). Figure 1 below displays how the IC's generation was modeled.

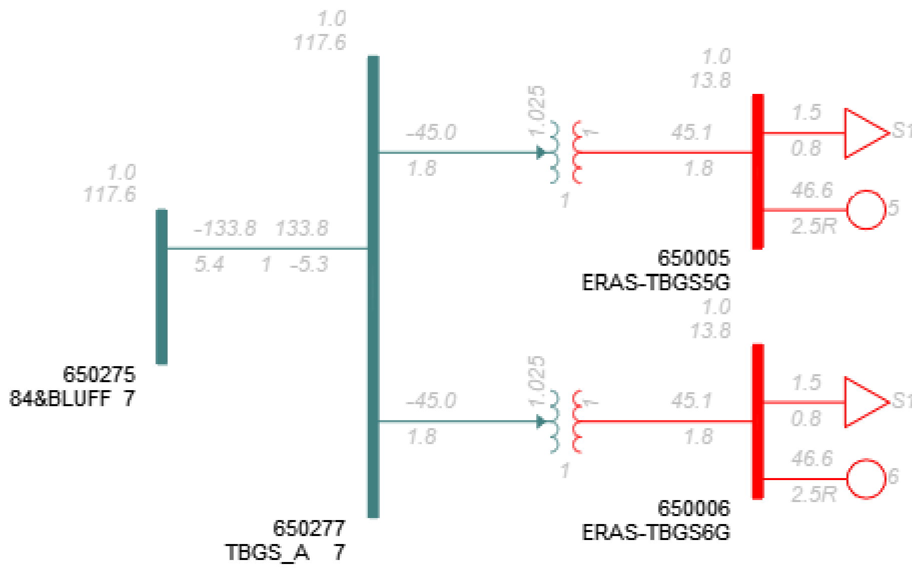


Figure 1: TBGS Units 5 and 6

Two sets of dynamic analyses were completed. This included evaluation at the modeled turbine maximum and the IC's requested maximum injection as shown in Table 1 of the Study Assumptions. To offset the additional generation included in these selected cases, the PSS/E scaling function was used to reduce generation in the surrounding Nebraska area by the corresponding 93.2/104 MW amount. This included generation from NPPD (640), HAST (641), GRIS (642), and OPPD (645).

These generation changes allowed LES to study these new interconnecting generators with expected existing local generation online to assess local machine dynamic interactions and to simulate stresses to tie-lines as this additional power is transferred outside of the LES footprint. Also, this adjustment in dispatch allows for a strong system swing bus which is necessary for starting dynamic contingency simulations. With these adjustments, the updated dynamic models were able to flat start and run a no-contingency simulation with no initial conditions suspect of interconnecting generators dynamic models. The initial conditions suspect output table for each flat start can be found in Appendix C.

The purpose of this dynamic analysis was to evaluate the stability impact of the IC's generation on the LES transmission system. This analysis evaluated 42 contingencies in the Summer Peak and Spring Light Load cases. These contingencies developed for the Annual LES System Performance Assessment represent the following categories from NERC standard TPL-001-5: P0, P1, P3, P4, P5, P6 and extreme events. These contingencies were chosen to fully study the dynamic impact these new generation interconnections have on the LES transmission system and the behavior associated with dynamic loads. Graphical output of the findings of each contingency simulation is available upon request. Appendix D provides addition information about the contingencies evaluated and the data plotted for each contingency.

Based on the results from this analysis, the LES transmission system exhibited stablity, positive damping, and acceptable transient voltages under both generation dispatch scenarios. The IC's generation successfully passed the criteria outlined in the SPP Disturbance Performance Requirements.

Project Cost Estimates, Lead Times and Scope of Work

Cost Estimates, Lead Times and Scope of Work (SOW) are identified below. The provided cost estimates bandwidth are considered "Study Estimates" as defined in SPP OATT Attachment AW Section 8.11.a. and are expected to be within a -20% to +20% variance from the final project cost. Provided lead times are based on LES's current project schedule and known procurement times. A one-line for S75 can be found in Appendix E.

S75 Scope of Work, Cost Estimate, and Lead Time

The IC's requested generators will interconnect directly into an existing generator tie-line that runs from TBGS to S75. This generator tie-line and S75 were appropriately sized to handle future expansion of TBGS. Proposed work at S75 will be minimal and will be completed within 24 months assuming an initial construction date of 1/04/2027. Scope of work consists of installing a new Phasor Measurement Unit at S75 along with the associated design and labor.

Interconnection Cost and Lead Time Estimate			
SCERT UID	**Upgrade Name**	**Cost Estimate**	**Lead Time**
95063/95064	Phasor Measurement Unit – S75	$ 44,275	24 Months

Summary and Recommendations

All simulated distubances were stable and had acceptable transient voltages. All study results are available upon request. Under system intact and contingency events, the LES system performance satisfies the criteria specified in the SPP Disturbance Performance Requirements. Therefore, this assessment of new generation interconnections to S75 demonstrates that there will be negligible impact to system reliability and stability. LES makes no additional upgrade recommendations for these generation interconnection requests beyond the new Phasor Measurement Unit at S75.

Appendix A

2025 LES FAC-002 ERAS-2025-001 IFS

GE LM6000 Dynamic Model Data

LES Resource & Transmission Planning Department

Table 2: GGOV Model Parameters (Typical)

Parameter	Description	Value	Units
Trate	Turbine Rating	46.6	MW
R	Permanent Droop	0.05	pu
Rselect	Feedback Signal for Droop	1.0	N/A
Tpelec	Electrical Power Transducer Time Constant	1.0	s
Maxerr	Maximum Value for Speed Error Signal	0.023	pu
Minerr	Minimum Value for Speed Error Signal	-0.023	pu
Kpgov	Governor Proportional Gain	2.4	pu
Kigov	Governor Integral Gain	1.1	pu
Kdgov	Governor Derivative Gain	0.0	pu
Tdgov	Governor Derivative Controller Time constant	1.0	s
Vmax	Maximum Valve Position Limit	1.00	pu
Vmin	Minimum Valve Position Limit	0.24	pu
Tact	Actuator Time Constant	0.4	s
Kturb	Turbine Gain	2.7	pu
Wfnl	No Load Fuel Flow	0.26	pu
Tb	Turbine Lag Time Constant	0.1	s
Tc	Turbine Lead Time Constant	0.0	s
Flag (not used)	Switch for Fuel Source Characteristic	0.0	N/A
Teng	Transport Lag Time Constant for Diesel Engine	0.0	s
Tfload	Load Limiter Time Constant	0.3	s
Kpload	Load Limiter Proportional Gain for PI Controller	1.0	pu
Kiload	Load Limiter Integral Gain for PI Controller	3.3	pu
Ldref	Load Limiter Reference Value	1.0	pu
Dm	Mechanical Damping Coefficient	0.0	pu
Ropen	Maximum Valve Opening Rate	99.0	pu/s
Rclose	Minimum Valve Closing Rate	-99.0	pu/s
Kimw	Power Controller (Reset) Gain	210	pu
Pmwset	Power Controller Setpoint	N/A	MW
Aset	Acceleration Limiter Setpoint	99.0	pu/s
Ka	Acceleration Limiter Gain	10.0	pu
Ta	Acceleration Limiter Time Constant	0.1	s
Db	Speed Governor Dead Band	0.0	N/A
Tsa	Temperature Detection Lead Time Constant	1.0	s
Tsb	Temperature Detection Lag Time Constant	1.0	s
Rup	Maximum Rate of Load Limit Increase	99.0	pu/s
Rdown	Maximum Rate of Load Limit Decrease	-99.0	pu/s

GE VERNOVA	Document Type: SPECIFICATION		Sheet Size A4
	Document Title: GGOV (V1.0) MODEL FOR LINCOLN ELECTRIC TERRY BUNDY		
Creation Date: 2026-02-03	Drawing Number: 7317767-000973	Revision -	Sheet 6 of 6

Generator, Compensator, Stabilizer, and Excitation Limiter Model Data Sheets

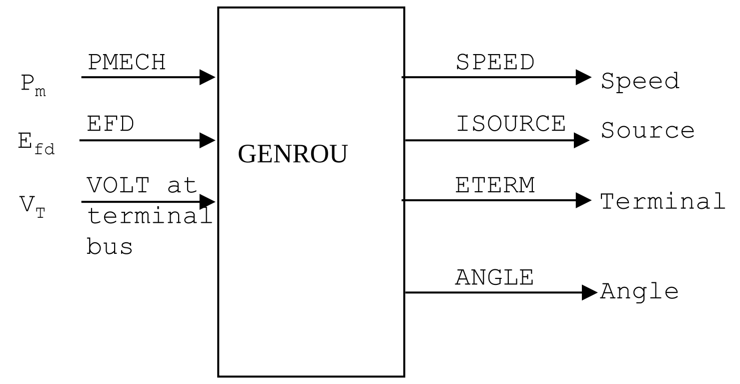
GENROU

GENROU, A4-Brush BDAX 7-290 ERJT 60 Hz Generator

ROUND ROTOR GENERATOR MODEL (QUADRATIC SATURATION)

This model is located at system bus # ______ IBUS,
machine # ______ I.
This model used CONs starting with # ______ J.

The machine MVA is **76.941** for each of 1 15 deg C
units = ______ MBASE.
ZSOURCE for this machine is 0 + j **0.195** on
the above MBASE.



ENGINE TYPE	PC/PF

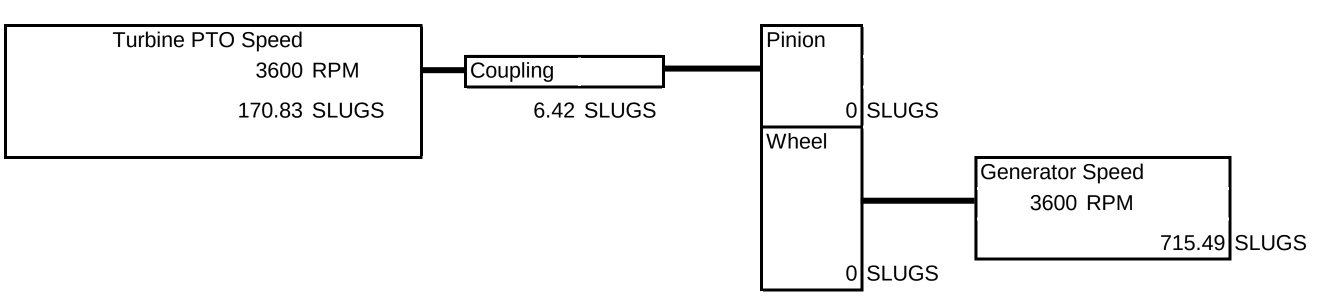
CONs	#	Value	Description
J		**7.230**	T'_{do} (>0) (Seconds) Transient Open Circuit Time Constant @ 100°C
J+1		**0.040**	T''_{do} (>0) (Seconds) Sub-transient Open Circuit Time Constant @ 100°C
J+2		**2.210**	T'_{qo} (>0) (Seconds) Quadrature Transient Open Circuit Time Constant @ 100°C
J+3		**0.040**	T''_{qo} (>0) (Seconds) Quadrature Sub-transient Open Circuit Time Constant @ 100°C
J+4		**1.118**	Inertia Constant, Complete Total Train, Engine, Generator, Coupling, RGB
J+5		**0.000**	Speed Damping D (Damping Torque Coefficient P.U)
J+6		**2.540**	X_d Unsaturated Synchronous Reactance - d axis
J+7		**2.320**	X_q Unsaturated Synchronous Reactance - q axis
J+8		**0.264**	X'_d Unsaturated Transient Reactance - d axis
J+9		**0.380**	X'_q Unsaturated Transient Reactance - q axis
J+10		**0.195**	X''_d Unsaturated Subtransient Reactance - d axis
J+11		**0.140**	X_l Unsaturated Stator Leakage Reactance
J+12		**0.110**	Saturation factor at 13,800 V (1.0)
J+13		**0.490**	Saturation factor at 16,560 V (1.2)

NOTE 1

X_d, X_q, X'_d, X'_q, X''_d, X''_q, X_l, H and D are in p.u., machine MVA base.

IBUS, 'GENROU', I, T'_{do}, T''_{do}, T'_{qo}, T''_{qo}, H, D, X_d, X_q, X'_d, X'_q, X''_d, X''_q, X_l, S(1.0), S(1.2)

H CONSTANT ROTATING TRAIN



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2.3. AC7B Model Parameters

Table 3: AC7B Excitation system Model Parameters

Parameters	Description	Values	Unit	Rev
KC	Rectifier Commutation Factor	0.2	-	-
KD	Load Factor	1.93	-	C
KDR	AVR Derivative Gain	0	-	-
KE	Alternator Gain	1	-	-
KF1	Field Voltage Feedback Gain	0	-	-
KF2	Field Current Feedback Gain	1	-	-
KF3	Rate Feedback Gain	0	-	-
KIA	FVR Integral Gain	0.67	pu/sec	C
KIR	AVR Integral Gain	40	pu/sec	-
KL	Lower Forcing Limit	10	p.u.	-
KP	Potential Forcing Term base of VAFAGe	93.81	p.u.	C
KPA	FVR Proportional Gain	0.804	pu	C
KPR	AVR Proportional Gain	40	pu	-
TDR	AVR Derivative Gain Filter (NA)	0	sec	-
TE	Exciter Open Time Constant	1.2	sec	C
TR	AVR Input Filter Time Constant	0.01	sec	-
TF	Rate Feedback Time Constant (Not used)	1	sec	-
VAmax	FVR Positive Limit	1	p.u.	-
VAmin	FVR Negative Limit	-0.99	p.u.	-
VEmax – E1	Maximum exciter EFD, pu @AFAG	5.53	p.u.	C
VE.75max – E2	75% Maximum exciter EFD, pu@AFAG	4.146	p.u.	C
SEmax – S(E1)	Saturation Factor at Maximum EFD	0.107	-	C
SE.75max – S(E2)	Saturation Factor at 75% Maximum EFD	0.014	-	C
VEMIN**	Exciter Field Current Lower Limit	0	p.u.	-
VFEMAX	Exciter Field Current Upper Limit base of AFAGe	91.87	p.u.	C
VRmax	AVR Positive Limit base of AFAGe	19.28	p.u.	C
VRmin	AVR Negative Limit base of AFAGe	0	p.u.	-

The above excitation system models values are given in IEEE base, the values given in AC7B table 3, are subject to update, in PSS settings report. The values table 3, can’t be one by one straight used or compared with the Software Settings.

Appendix B

2025 LES FAC-002 ERAS-2025-001 IFS

SPP Disturbance Performance Requirements

LES Resource & Transmission Planning Department

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Planner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations following a disturbance on the Bulk Electric System for all NERC TPL-001-4 P1 through P7 events.

Machines with rotor angle deviations greater than or equal to 16 degrees (measured as absolute maximum peak to absolute minimum peak) shall be evaluated against SPPR1 or SPPR5 requirements below. Machines with rotor angle deviations less than 16 degrees which do not exhibit convergence shall be evaluated on an individual basis. Rotor angle deviations will be calculated relative to the system swing machine.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio One (SPPR1) must be less than or equal to 0.95 where SPPR1 is calculated as follows:

$$\text{SPPR1} = \frac{\text{Peak Rotor Angle of 2nd Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of 1st Positive Peak minus Minimum Value}} \leq 0.95$$

-or- Damping Factor % = (1 – SPPR1) x 100% ≥ 5%

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of 6th Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of 1st Positive Peak minus Minimum Value}} \leq 0.774$$

-or- Damping Factor % = (1 – SPPR5) x 100% ≥ 22.6%

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 & 2 below.

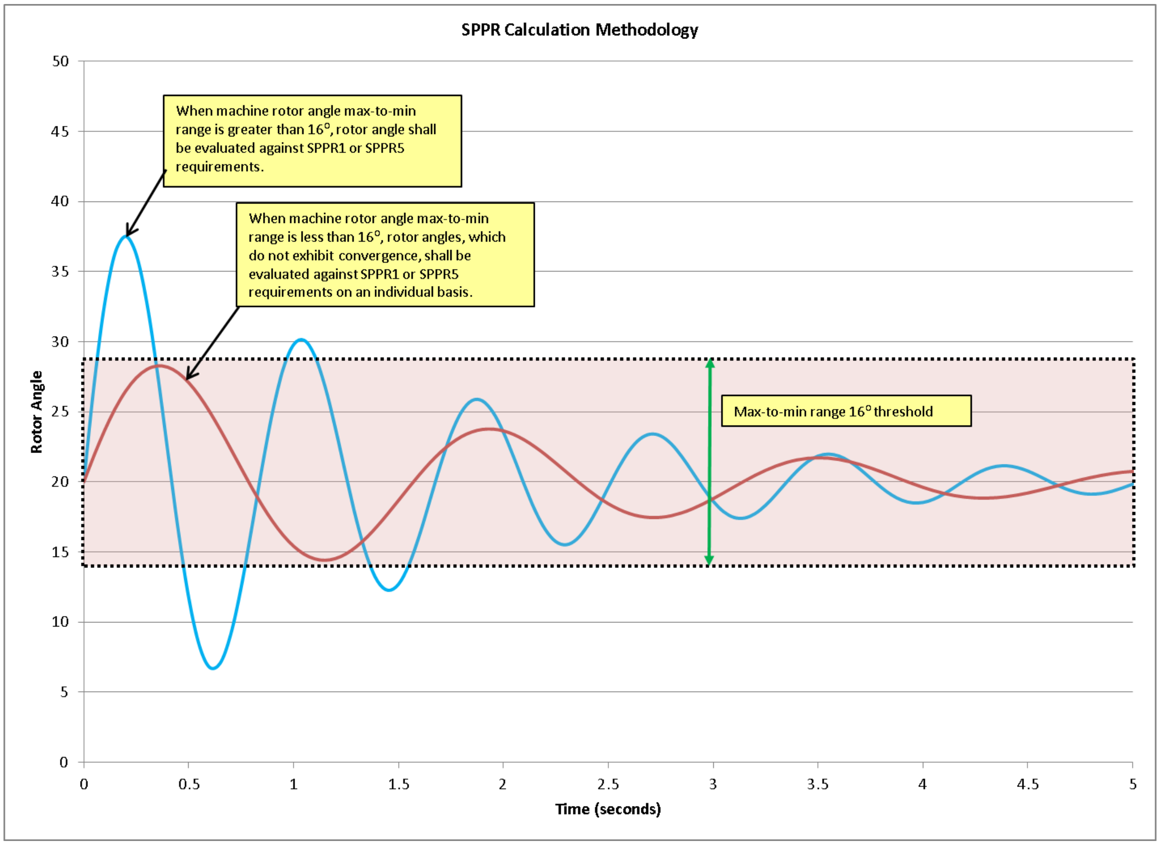

Figure 1. Applicability of 16 Degree Threshold

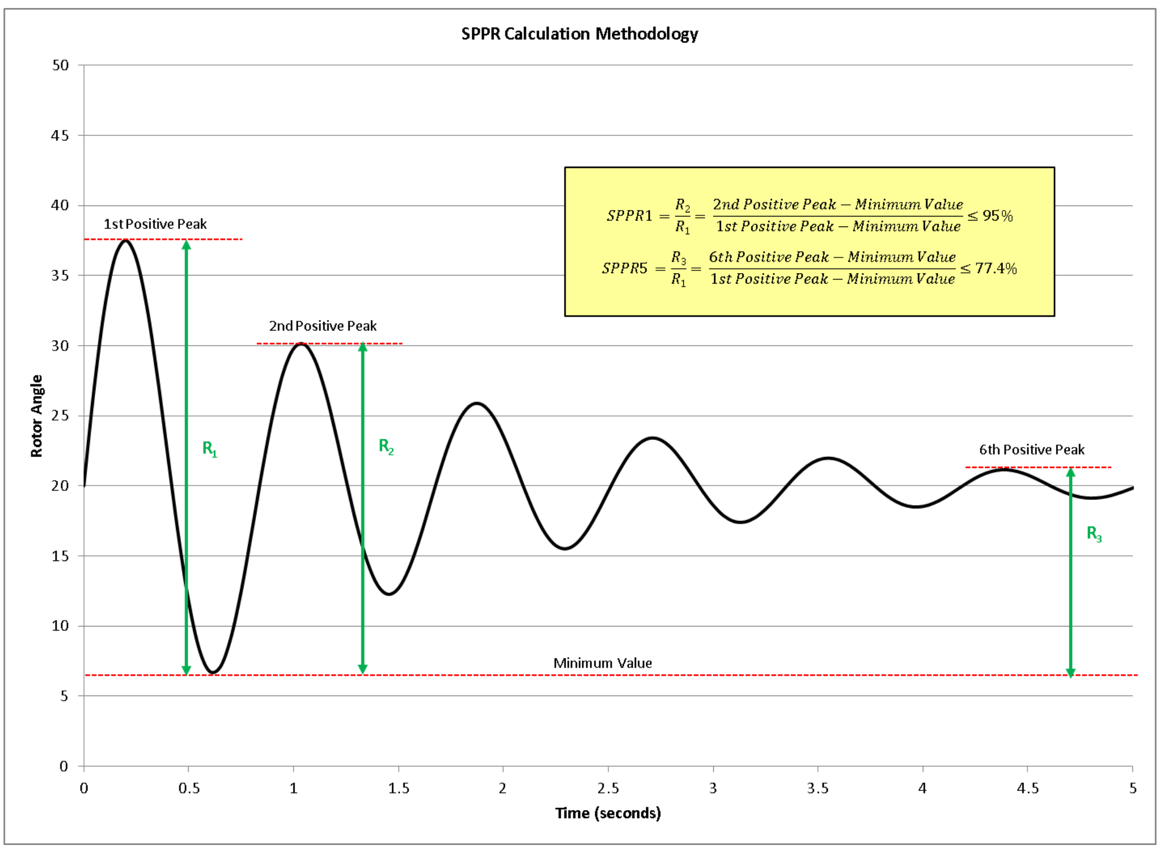

Figure 2. SPPR1 and SPPR5 Calculations

TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Bus voltages on the Bulk Electric System shall recover above 0.70 per unit, 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared, unless affected transmission system elements are designed to handle the rise above 1.2 per unit.

Qualitatively, this Requirement is shown in Figure 3 below.

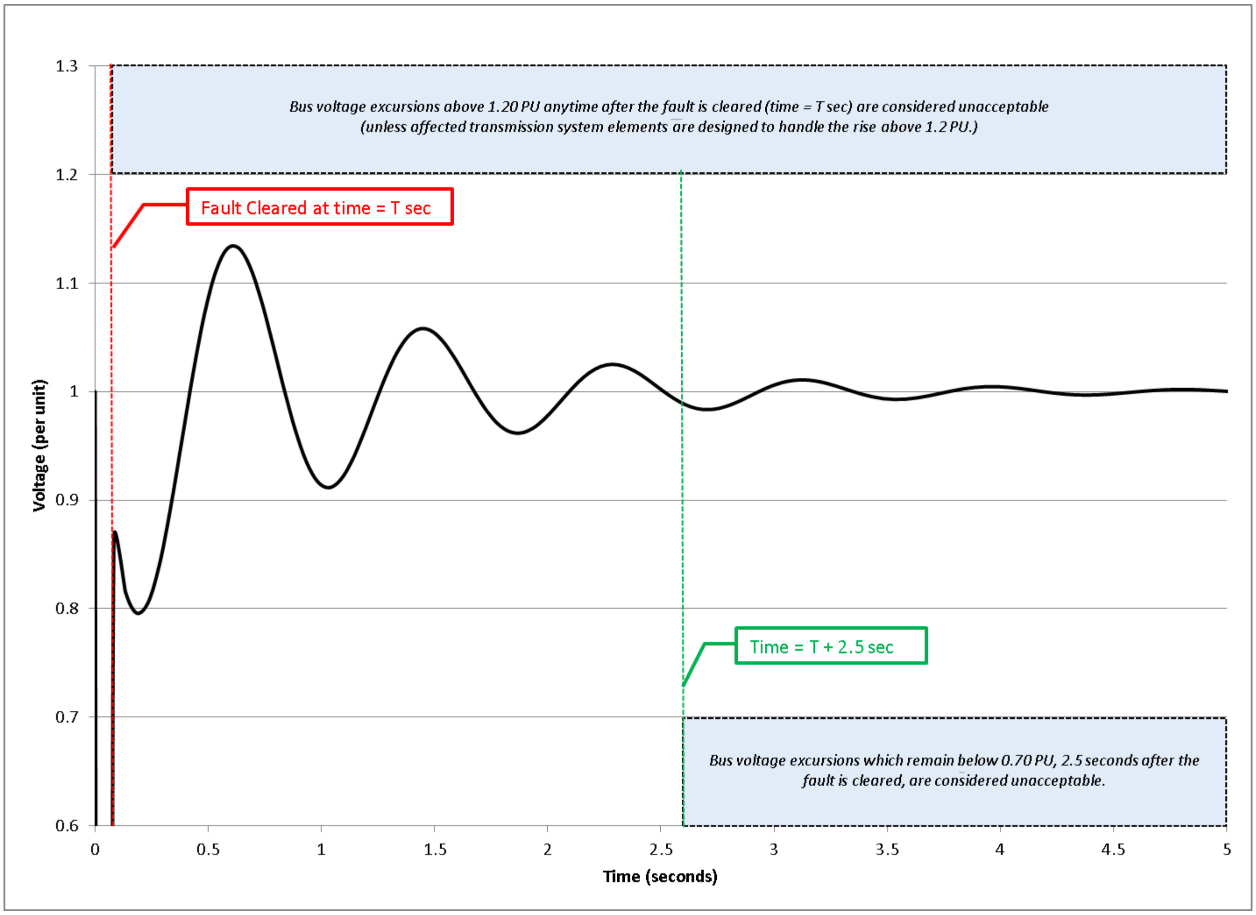

Figure 3. Transient Voltage Recovery Requirement

Appendix C

2025 LES FAC-002 ERAS-2025-001 IFS

Flat Start Initial Conditions Suspect

LES Resource & Transmission Planning Department

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INITIAL CONDITIONS SUSPECT:
   I  DSTATE(I)    STATE(I)     MODEL           STATE     BUS#-SCT X-- NAME --X BASKV  ID
 34788  -0.32387      0.51819     UEL2            K+3    300002     1THLG2      22.000  1
 34804    9.9835     -10.000     UEL2C           K+5    300006     1NM G1      22.000  1
 34805    9.9835     -10.000     UEL2C           K+6    300006     1NM G1      22.000  1
 34813    9.9496     -10.000     UEL2C           K+5    300007     1NM G2      22.000  1
 34814    9.9496     -10.000     UEL2C           K+6    300007     1NM G2      22.000  1
 34866  -0.33715      0.53944     UEL2            K+3    335371     1ACADIA_C25 18.000  1
 34989  -0.21528      0.34445     UEL2            K+3    344064     1AUDRN G4   13.800  4
 35093  -0.16659      0.13494     UEL2            K+3    344897     1LAB   G4   20.000  4
 35114  -0.13751      0.22002     UEL2            K+3    345501     1PNKY 1     13.800  1
 35149  -0.22052      0.35283     UEL2            K+3    345671     1RUSH  G2   18.000  2
 35163  -0.42791E-01  0.68466E-01 UEL2            K+3    345756     1SIOUX 1    18.000  L
 35170  -0.45097E-01  0.72155E-01 UEL2            K+3    345832     1TAUM S G1  13.800  1
 35523  -0.55141      0.82712E-01 UEL2            K+3    383511     2ROCKY MTN 120.000  1
 35615  -0.20720      0.33152     UEL2            K+3    635691     GDMECGT1    18.000  1
 35622  -0.20702      0.33123     UEL2            K+3    635692     GDMECGT2    18.000  2
 35674    10.000     -10.000     UEL2C           K+4    693340     R1010_WES1-413.800  1
 35683    10.000     -10.000     UEL2C           K+4    693340     R1010_WES1-413.800  2
 35692    10.000     -10.000     UEL2C           K+4    693340     R1010_WES1-413.800  3
 35701    10.000     -10.000     UEL2C           K+4    693340     R1010_WES1-413.800  4
 35708  -0.35635E-04  0.16282E-02 UEL2C           K+2    693341     R1010_WES5-713.800  5
 35710    10.000     -10.000     UEL2C           K+4    693341     R1010_WES5-713.800  5
 35719    10.000     -10.000     UEL2C           K+4    693341     R1010_WES5-713.800  6
 35728    10.000     -10.000     UEL2C           K+4    693341     R1010_WES5-713.800  7
 35872  -0.80227E-01  0.16045     UEL2            K+3    514944     HSL   9G    13.800  1
 35879  -0.78588E-01  0.15718     UEL2            K+3    514945     HSL  10G    13.800  1
 35898  -0.20000      0.20000     UEL2C           K+4    515223     MUSKOG4G    18.000  1
 36012  -0.53520E-01  0.85632E-01 UEL2            K+3    532741     EMPEC341    13.800  3
 36019  -0.53520E-01  0.85632E-01 UEL2            K+3    532741     EMPEC341    13.800  4
 36026  -0.13014      0.20822     UEL2            K+3    532742     EMPEC5 1    18.000  5
 36158   0.97404     -1.0000     UEL2C           K+5    640011     GENTLM2G    24.000  2
 36159   0.97404     -1.0000     UEL2C           K+6    640011     GENTLM2G    24.000  2
 36167    157.02     -11.000     UEL2C           K+5    640020     SHELDN2G    13.800  2
 36218  -0.34520      0.55231     UEL2            K+3    652461     GARISN5G    13.800  5
 38166  -0.42915E-01   0.0000     AC8B            K+2    337720     1CARPENTR U213.800  1
 38167  -0.24390E-01   1.4295     AC8B            K+3    337720     1CARPENTR U213.800  1
 47661  -0.71836E-01   2.3751     ESAC8B          K+3    516133     TINKER2G    13.800  2
 53263   0.24859      0.17965     GAST2A          K+5    383662     2DAHLBERG 2 13.800  2
 53312   0.12009      0.60371     GAST2A          K+5    383666     2DAHLBERG 6 13.800  6
 53338   0.12009      0.60371     GAST2A          K+5    383668     2DAHLBERG 8 13.800  8
 53361   0.12009      0.60371     GAST2A          K+5    383670     2DAHLBERG 1013.800  10
 53602   0.29530      0.25496E-01 GAST2A          K+5    383748     2WARTHEN 6  13.800  6
 53615   0.29530      0.25496E-01 GAST2A          K+5    383749     2WARTHEN 7  13.800  7
 53628   0.29530      0.25496E-01 GAST2A          K+5    383750     2WARTHEN 8  13.800  8
 53795   0.90341     -1.9812     GAST2A          K+5    383855     2TIGER CK1  18.000  1
 53808   0.90341     -1.9812     GAST2A          K+5    383856     2TIGER CK2  18.000  2
 53821   0.90341     -1.9812     GAST2A          K+5    383857     2TIGER CK3  18.000  3
 53834   0.90341     -1.9812     GAST2A          K+5    383858     2TIGER CK4  18.000  4
```

54446	0.11842	0.60922	GAST2A	K+5	386450	2GREENCOA 13.800 A
54459	0.11842	0.60922	GAST2A	K+5	386451	2GREENCOB 13.800 B
54472	0.11842	0.60923	GAST2A	K+5	386452	2GREENCOC 13.800 C
54485	0.11841	0.60923	GAST2A	K+5	386453	2GREENCOD 13.800 D
54498	0.11842	0.60923	GAST2A	K+5	386454	2GREENCOE 13.800 E
54511	0.11842	0.60923	GAST2A	K+5	386455	2GREENCOF 13.800 F
54524	0.11841	0.60923	GAST2A	K+5	386456	2GREENCOG 13.800 G
54537	0.11842	0.60923	GAST2A	K+5	386457	2GREENCOH 13.800 H
60898	0.23401	0.92777	GAST2A	K+5	656573	WISDOM G 69.000 2
216884	6045.0	-2.0000	CDCSID	K+3	652584	SIDNEYW4 230.00 MRO_10_SIDDC
216936	0.50590	0.20000	WELDCC	K+18	508847	WELSHDC1 345.00 WELSH-HVDC
216991	-0.65272E-01	0.0000	WELDCC	K+73	508847	WELSHDC1 345.00 WELSH-HVDC
219047	0.14284E-02	0.15728E-02	WT2G1	K	620115	G380 RUGBY W0.6000 W
224550	0.12860E-02	0.11081	WT2E1	K+1	600123	G536 JHDEERW0.5750 W
224995	0.10881E-02	0.10156	WT2E1	K+1	620451	G474 GRNT CW41.600 W
232323	-22.042	0.0000	WT3P1	K+2	274850	MENDOTA H;RU0.6900 W
232326	-25.824	0.0000	WT3P1	K+2	274851	PROVIDENC;RU0.6900 W3
232347	-24.588	0.0000	WT3P1	K+2	274861	TOP CROP ;1U0.6900 W1
232350	-25.909	0.0000	WT3P1	K+2	274862	TOP CROP ;2U0.6900 W2
232365	-24.709	0.0000	WT3P1	K+2	274877	BISHOP HL;1U0.6900 W1
232368	-24.709	0.0000	WT3P1	K+2	274878	BISHOP HL;2U0.6900 W2
232371	-24.600	0.0000	WT3P1	K+2	274879	MINONK ;1U0.6900 W1
233687	17.000	0.0000	WTPTA1	K	543654	PRQNW_G1_1 0.6900 W1
233688	0.51087	0.0000	WTPTA1	K+1	543654	PRQNW_G1_1 0.6900 W1
238825	0.60000E-03	0.44111E-01	REPCTA1	K+2	530634	SMKYP1V100 0.6900 1
238826	0.70588E-03	0.44111E-01	REPCTA1	K+3	530634	SMKYP1V100 0.6900 1
239305	-0.27059E-01	0.66463	REPCA1	K+4	645201	PLTV 1P 0.6300 PV
264502	0.11958E-03	0.49935E-02	CMLDBLU2	K	337911	1ANO U2 22.000 AX
331600	0.54258E-04	-0.11997E-02	CMLDBLU2	K+3	620164	LANGDON9 41.600 T0
349555	0.54426E-04	0.21374E-02	CMLDBLU2	K+3	658096	BRANDN 9 41.600 T0
349580	0.11204E-03	0.13268E-02	CMLDBLU2	K+1	658103	ELBOWLK9 41.600 BB
349582	0.10595E-03	0.98451E-02	CMLDBLU2	K+3	658103	ELBOWLK9 41.600 BB

Appendix D

2025 LES FAC-002 ERAS-2025-001 IFS

Disturbance Category Description

LES Resource & Transmission Planning Department

LINCOLN ELECTRIC SYSTEM Single Line-to-Ground and 3-Phase Faults		
3-Phase and SLG Faults, No Prior Outage		
Case	Category	Description
0	P0	No fault simulation
1	P1	A 3 cycle, 3-phase fault at the NW 68th & Holdrege 345-kV end of the NW 68th & Holdrege – Moore 345-kV line.
2	P1	A 3 cycle, 3-phase fault at the Wagener 345-kV end of the Wagener – 103rd & Rokeby 345-kV line.
3	P1	A 3 cycle, 3-phase fault at the 103rd & Rokeby 345-kV end of the 103rd & Rokeby – S3458 345-kV line.
4	P1	A 3 cycle, 3-phase fault at the Wagener 345-kV end of the Wagener – S3454 345-kV line.
5	P3	There is a prior outage of the TBGS 2-on-1 combined cycle units. A 3 cycle, 3-phase fault at the NW 68th & Holdrege 345-kV end of the NW 68th & Holdrege – Moore 345-kV line.
6	P3	There is a prior outage of the TBGS 2-on-1 combined cycle units. A 3 cycle, 3-phase fault at the Wagener 345-kV end of the Wagener – 103rd & Rokeby 345-kV line.
7	P4	A 3 cycle, SLG fault at the NW 68th & Holdrege 345-kV end of the NW 68th & Holdrege – Moore 345-kV line, Breaker #3003 fails, and the NW 68th & Holdrege 345/115-kV autotransformer is opened to clear the fault.
8	P4	A 3 cycle, SLG fault at the Wagener 345-kV end of the Wagener – 103rd & Rokeby 345-kV line, Breaker #3003 fails, and the Wagener 345/115-kV autotransformer #2 is opened to clear the fault.

9	P5	A 3 cycle, SLG fault on breaker 3003 at NW 68th & Holdrege. Breakers 3001 and 3005 open after a 20-cycle delay caused by a relay failure to operate, which opens the NW 68th & Holdrege – Moore 345-kV line and NW 68th & Holdrege 345/115-kV autotransformer to clear the fault.
10	P5	A 3 cycle, SLG fault on breaker 1003 at Wagener. Breakers 1001 and 1005 open after a 20-cycle delay caused by a relay failure to operate, which opens the Wagener – 103rd & Rokeby 345-kV line and Wagener 345/115-kV autotransformer #2 to clear the fault.
11	P5	A SLG fault on 345kV side of T852 at Wagener with a single point failure of the DC supply at Wagener. Breakers CB3001 and CB3003 at Wagener open after a 3-cycle delay which isolates the 345kV side of T852. After a 62-cycle delay, CB1001 at 120th & Alvo and CB1002 and CB1003 at 84th & Leighton open isolating 120th & Alvo – Wagener and 84th & Leighton – Wagener. After another 9-cycle delay, CB3002 and CB3004 isolates T851 at Wagener. Then after 56 cycles CB7101 and CB7102 isolates 81st & Old Cheney – Wagener to clear the fault.
12	P5	A SLG fault on the 27th & Pine Lake Road end of 27th & Pine Lake Road – Rokeby line with a single point failure of the DC supply at 27th & Pine Lake Road. Breaker CB1001 at 27th & Pine Lake Road opens after a 5-cycle delay which isolates 27th & Pine Lake Road. After a 25-cycle delay, CS9020 and CS9030 at Rokeby open isolating Rokeby – RGS Unit #2 and Rokeby – RGS Unit #3. After another 35-cycle delay, CB1004 and CB1005 at NW68 th & Holdrege isolates NW68 th & Holdrege – Rokeby, also CB1003 and CB1004 at Folsom & Pleasant Hill isolates Folsom & Pleasant Hill – Rokeby. Then after 15 cycles CS9010 at Rokeby isolates Rokeby – RGS Unit #1 to clear the fault.
13	P5	A SLG fault on the 19th & Alvo end of 19th & Alvo – 56th & I80 line with a single point failure of the DC supply at 19th & Alvo. Breakers CB1002 and CB1003 open after a 5-cycle delay which isolates 19th & Alvo. After a 65-cycle delay, CB7502 and CB7504 at 84th & Bluff open isolating 70th & Bluff – 84th & Bluff. After another 65-cycle delay, CB1104 open at NPPD's Davey substation isolating 70th & Bluff – Davey.
14	P6	There is a prior outage of the NW 68th & Holdrege – Moore 345-kV line. A 3 cycle, 3-phase fault at the Wagener 345-kV end of the Wagener – 103rd & Rokeby 345-kV line.
15	P6	There is a prior outage of the Wagener – 103rd & Rokeby 345-kV line. A 3 cycle, 3-phase fault at the NW 68th & Holdrege 345-kV end of the NW 68th & Holdrege – Moore 345-kV.

16	P6	There is a prior outage of the 103rd & Rokeby - Moore 345-kV line. A 3 cycle, 3-phase fault at the NW 68th & Holdrege 345-kV end of the NW 68th & Holdrege – Moore 345-kV.
17	P6	There is a prior outage of the Wagener – S3454 345-kV line. A 3 cycle, 3-phase fault at the 103rd & Rokeby 345-kV end of the 103rd & Rokeby – S3458 345-kV line.
18	P6	There is a prior outage of the Wagener – Columbus East 345-kV line. A 3 cycle, 3-phase fault at the Wagener 345-kV end of the Wagener – S3454 345-kV line.
19	EE	A 23 cycle, 3-phase fault on the Moore end of the Moore – 103rd & Rokeby 345-kV line.
Terry Bundy Generating Station (TBGS)		
20	P1	A 5 cycle, 3-phase fault at 84th & Bluff 115-kV end of the 84th & Bluff – 70th & Bluff 115-kV line.
21	P1	A 5 cycle, 3-phase fault at 84th & Bluff 115-kV end of the 84th & Bluff – Waverly 115-kV line.
22	P1	A 5 cycle, 3-phase fault at the 84th & Bluff 115-kV end of the 84th & Bluff – TBGS_B 115-kV line. (This disturbance drops TBGS units No. 1, No. 2 and No. 3)
23	P2	A 5 cycle, SLG fault on breaker 7503 at 84th & Bluff. Breakers 7501 and 7505 open, which drops TBGS units No. 1, No. 2, No. 3, No. 4, and TBGS LFGTE.
24	P4	A 5 cycle, SLG fault at the 84th & Bluff 115-kV end of the line 84th & Bluff – TBGS_B (L7577B), Breaker #7503 fails, and Breaker #7501 is opened to clear the fault. (This disturbance drops all TBGS generation.)
25	P4	5 cycle, SLG fault at the 84th & Bluff 115-kV end of the 84th & Bluff – Waverly 115-kV line. Breaker #7502 fails, and the 84th & Bluff – 70th & Bluff 115-kV line is opened to clear the fault.

26	P5	A 5 cycle, SLG fault on breaker 7503 at 84th & Bluff. Breakers 7501 and 7505 open after a 20-cycle delay caused by a relay failure to operate, which drops TBGS units No. 1, No. 2, No. 3, No. 4, and TBGS LFGTE.
27	P5	A SLG fault on TBGS Unit #1 with a single point failure of the DC supply at TBGS. Breakers CB7503 and CB7505 at 84th & Bluff open after a 15-cycle delay which isolates TBGS to clear the fault. (This disturbance drops TBGS Units #1-3 generation.)
28	P5	A SLG fault on TBGS Unit #4 with a single point failure of the DC supply at TBGS. Breakers CB7501 and CB7503 at 84th & Bluff open after a 15-cycle delay which isolates TBGS to clear the fault. (This disturbance drops TBGS Unit #4 generation.)
29	P6	There is a prior outage of the 84th & Bluff – Waverly 115-kV line. A 5 cycle, 3-phase fault at the 84th & Bluff 115-kV end of the 84th & Bluff – 70th & Bluff 115-kV line.
30	P6	There is a prior outage of the 84th & Bluff – 84th & Fletcher 115-kV line. A 5 cycle, 3-phase fault at the 84th & Bluff 115-kV end of the 84th & Bluff – 70th & Bluff 115-kV line.
31	P6	There is a prior outage of the 84th & Bluff – 70th & Bluff 115-kV line. A 5 cycle, 3-phase fault at the 84th & Bluff 115-kV end of the 84th & Bluff – Waverly 115-kV line.
32	EE	A 5 cycle, 3-phase fault on breaker 7503 at 84th & Bluff. Breakers 7501 and 7505 open, which drops TBGS units No. 1, No. 2, No. 3, No. 4, and TBGS LFGTE.
Rokeby Generation Station (RGS)		
33	P1	A 5 cycle, 3-phase fault at the Rokeby 115-kV end of the Rokeby – Folsom & Pleasant Hill 115-kV line.
34	P1	A 5 cycle, 3-phase fault at the Rokeby end of the multiple circuit tower line that includes the 115-kV lines from Rokeby - NW 68th & Holdrege and Rokeby – Folsom & Pleasant Hill.
35	P2	A 5 cycle, SLG fault on breaker 9003 at Rokeby. Breakers 9002 and 9006 open, which drops Rokeby units No. 1 and No. 3.

36	P4	A 5 cycle, SLG fault at the Rokeby 115-kV end of the Rokeby – Folsom & Pleasant Hill 115-kV line, Breaker #9005 fails, and the Rokeby – 27th & Pine Lake Road 115-kV line is opened to clear the fault.
37	P5	A 5 cycle, SLG fault on breaker 9003 at Rokeby. Breakers 9002 and 9006 open after a 20-cycle delay caused by a relay failure to operate, which drops Rokeby units No. 1 and No. 3.
38	P5	A SLG fault on RGS Unit #1 with a single point failure of the DC supply at RGS. Breakers CB9003 and CB9006 at Rokeby open after a 5-cycle delay which isolates RGS to clear the fault. (This disturbance drops RGS Unit #1 generation.)
39	P6	There is a prior outage of the Rokeby – 27th & Pine Lake 115-kV line. A 5 cycle, 3-phase fault at the Rokeby 115-kV end of the Rokeby – Folsom & Pleasant Hill 115-kV line.
40	P6	There is a prior outage of the Rokeby – NW 68th & Holdrege 115-kV line. A 5 cycle, 3-phase fault at the Rokeby 115-kV end of the Rokeby – Folsom & Pleasant Hill 115-kV line.
41	P6	There is a prior outage of the Rokeby – NW 68th & Holdrege 115-kV line. A 5 cycle, 3-phase fault at the Rokeby 115-kV end of the Rokeby – 27th & Pine Lake 115-kV line.
42	EE	A 5 cycle, 3-phase fault on breaker 9003 at Rokeby. Breakers 9002 and 9006 open, which drops RGS units No. 1, and No. 3.

The following plots are created for each disturbance:

- LES Generation (TBGS 1-6, Rokeby 1-3, J Street, and Council Bluffs Unit 4)
  - Rotor angle
  - Active power
  - Reactive power
  - Terminal voltage
  - Frequency

- LES Bus Voltages
  - Wagener 345-kV
  - NW 68th & Holdrege 345-kV
  - 103rd & Rokeby 115-kV
  - 70th & Bluff 161-kV
  - 70th & Bluff 115-kV
  - Wagener 115-kV
  - NW 68th & Holdrege 115-kV
  - Rokeby 115-kV
  - 84th & Bluff 115-kV

- LES Tie Line (MW) Flows
  - L3442 345-kV
  - L3472 345-kV
  - L3503 345-kV
  - L3516 345-kV
  - L3521 345-kV
  - L1559 161-kV
  - L1156B 115-kV
  - L1181B 115-kV
  - L1099 115-kV
  - L1197 115-kV

- LES Branch (MW) flows
  - L1485 345-kV
  - L8589 345-kV
  - L1490 115-kV
  - L2990 115-kV
  - L4290 115-kV
  - L6775B 115-kV
  - L6975 115-kV
  - L7583 115-kV

- NPPD Rotor Angles
  - Sheldon units
  - Cooper unit

- NPPD Bus Voltages
  - Moore 345-kV
  - Columbus East 345-kV
  - Sheldon 115-kV
  - Pawnee Lake 115-kV
  - Davey 115-kV

- OPPD Rotor Angles
  - Nebraska City units

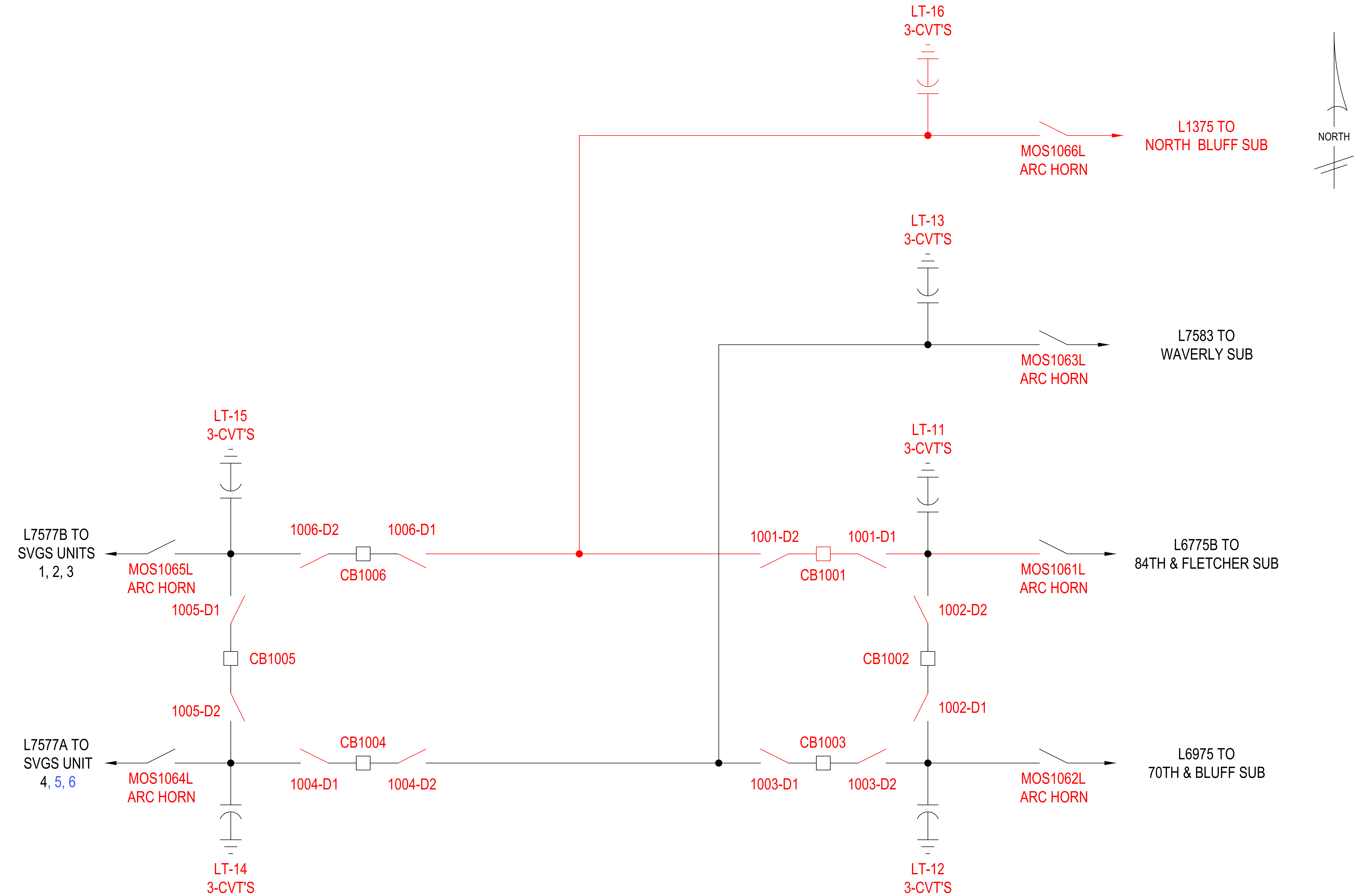
- OPPD Bus Voltages
  - Sub 1214 161-kV
  - Sub 3454 345-kV
  - Sub 3458 345-kV

Appendix E

2025 LES FAC-002 ERAS-2025-001 IFS

84th & Bluff Substation One-Line

LES Resource & Transmission Planning Department



INSTALL GP 02/06/2025 #5039704

GP 02/06/2025 TERM ADDITION #5039704
JB 02/06/2025 ADD INTERRUPTER LABELS UPDATE FORMAT
GP 11/13/2003 ADD UNIT NUMBERS
RB 06/12/2002 OLD DWG #OS-A-75-031
REVISIONS

LES LINCOLN ELECTRIC SYSTEM

BASE		
DRAWN BY	G PELLA	04/24/2002
DESIGNED BY	E STEFFEN	04/24/2002
CHECKED BY		
CHECKED BY		
APPROVED BY		

NETWORK:
W.O.
JOB:
D.N.
STR.
SCALE:

S075 - 84TH & BLUFF SUBSTATION
1-LINE DIAGRAM - 115kV

E-0200

DRAWING NO.
000505
SHT. 1 of 1

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