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BEFORE THE GUAM PUBLIC UTILITIES COMMISSION

IN THE MATTER OF:	**DOCKET NO. 07-10**
Guam Power Authority's Filing Regarding Long-Range Transmission Planning Study	**FILING RE LONG-RANGE TRANSMISSION PLANNING STUDY**

COMES NOW, the GUAM POWER AUTHORITY (GPA), by and through its counsel of record, D. GRAHAM BOTHA, ESQ., and hereby files its Long-Range Transmission Planning Study. The long range study looks at the loads resulting from the military buildup on Guam and the expansion in load growth over the next decade. Most of the military load is scheduled to occur before 2015. GPA is also examining renewable energy, such as wind power and solar, to help reduce its high cost of fuel for power generation. The transmission study's main focus is to evaluate options for supply of increased military loads and connection of proposed new wind generation facilities.

RESPECTFULLY SUBMITTED this 9th day of June, 2010.

D. GRAHAM BOTHA, ESQ.
GPA Legal Counsel

COPY

FY 2010
LONG-RANGE TRANSMISSION PLANNING STUDY

GUAM POWER AUTHORITY
May 2010

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Section 1 Executive Summary

1.1 Background

Significant power system upgrades and additions have taken place since the last long-range transmission plan was prepared in 1997. Most notable are the addition of 120MW of generation capacity in the Cabras-Piti complex and the completion of a 115-kV looped, backbone, 115-kV transmission system from Piti to Harmon Substation, covering the load center of GPA's service territory. The peak load has remained nearly unchanged or decreased slightly, from 1997 to today. Looking ahead, loads resulting from the military's expansion represent the majority of the non-generic projected load growth over the next decade, with a projected peak load contribution on the order of 60 to 70 MW. Most of the increase in the military's load is scheduled to occur before 2015. Further, GPA is looking at options for renewable energy to help reduce its high cost of fuel for power generation. Wind power is considered to be a likely source of renewable energy over the next few years and a viable location for new wind generation facilities has been determined. This study's main focus is to evaluate options for supply of the new military loads and connection of the new wind generation facilities.

1.2 Scope

This study focuses on:

- Determining transmission facilities requirements for supporting the planned DoD buildup
- Reviewing preliminary options for connection of planned renewable energy resources
- Reviewing potential for loss reductions by application of shunt capacitors.

1.3 Recommendations

Complete projects in Appendix K including remaining project recommendations from the FY 1997 Long Range Transmission Plan.

The transmission expansion plan upgrades recommended by 2020 include:

1. Reconductor 34.5-kV overhead Piti – Cold Storage-Orote line with 927 kcmil conductor.
2. Construct new 34.5-kV overhead line from Piti to Polaris Point (remove Polaris Pt. from Piti-Apra Heights circuit)
3. Install 2x6 MVAR capacitor banks at Orote
4. Install 2x3 MVAR capacitor banks at Polaris Point

5. Construct a new Harmon - Anderson 115kV line, and build new 115 kV substation at Andersen.
6. Reconductor Harmon - Anderson 34.5 kV to 927 kcmil.
7. Install 2x6 MVAR capacitor banks at Anderson, North Finegayan.
8. Install 2x3 MVAR capacitor banks at North Ramp.

The cost range for these projects is between $60 MM and $67 MM.

GPA should compensate for reactive loads up to 98% power factor. Addition of 32 MVARs of capacitors in FY 2010 at a cost of $1,555,200 has a payback of 5 years. For the recommended system additions under FY2020 loads, an additional 44 MVARs of capacitors installed by FY 2020 has a payback period of 2.5 years.

1.4 Study Methodology

As part of this Long Range Transmission Study, GPA

- Created a Spatial Forecast for Substation Loads
- Determined Scope
- Gathered Planning Process Inputs
- Determined Key Assumptions
- Created and Validated the Power Flow Base Case
- Performed a Situation Analysis
- Performed Preliminary Power Flow Analysis
- Formed Candidate Expansion Plans
- Evaluated Candidate Expansion Plans
- Addressed System Losses
- Discussed Operational Considerations.

1.5 Results Discussion Summary

GPA and R.W. Beck ran combinations of cases in Appendix R for island-wide candidate expansion plans. The NorthF-SouthA2 plan exhibited the best system performance of all island-wide candidate expansion plans. GPA observed the following from the results of study cases:

1 The NorthF-SouthA2 plan upgrades will alleviate the projected thermal violations for N-1 contingencies for all dispatch scenarios (except full wind at 160 MW) with the exception of Agana-Radio Barrigada 34kV and Agana-Tamuning 115kV.
2 No voltage violations for N-1 contingencies.
3 Accommodating Transient Peak 2 (ARG) requires reconductoring of Piti – Cold Storage – Orote 34kV. Accommodating Transient Peak 1 (CVN) does not.
4 New Harmon - Anderson 115kV (with reconductoring of the 34kV) resolves thermal overloads in the North, new Harmon - Anderson U/G 34kV does not. A new Harmon-Andersen U/G 34.5 kV line will hog the load leaving the other lines leading into Andersen very lightly loaded unless a split bus arrangement is in place.

5 Piti - Harmon and Tamuning – Harmon 115kV N-2 results in some thermal violations and low voltages for the base dispatch. Dispatch in the north relieves violations. Interrupting GWA load using the Smart Grid Load Control Management System and dispatch in the north relieves violations.

The following 34.5kv/13.8 kV transformers will overload prior to the fiscal years indicated:

- AganaT65 (prior to FY 2013)
- TumonT60 (prior to FY 2016)
- DededT55 (prior to FY 2013)
- NCS T47 (prior to FY 2011).

These transformers will have the following overloads by 2020:

- AganaT65 (118% loading)
- TumonT60 (123% loading)
- DededT55 (102% loading)
- NCS T47 (420% loading).

1.6 Conclusions

Time is of the essence to construct these projects within the aggressive schedule dictated by the 2014 Marines to Guam relocation. GPA must seek to temporarily augment its staff or have DoD construct many of these projects.

GPA should explore using High Thermal Limit cable to reconductor lines with a higher probability of thermal overload such as ACSS and ACSS/TW cable. It should also explore dynamic thermal rating for critical lines. It should consider using short-term and long-term thermal emergency ratings for lines, and create appropriate operations practices.

Section 2 Situation Analysis

Guam Power Authority's last published a long-range transmission plan in the second quarter of FY 1997. The 1997 Long-Range Transmission Plan (LRTP) focused on the integration of the TEMES CT and the MEC Independent Power Producer (IPP) power facilities into the GPA power system grid. The chief benefit of this effort included the integration of the new generation facilities and the construction of the Piti-Harmon 115 kV line. The Piti-Harmon line solved the problems caused by the simultaneous outage on the same structure of the two Cabras-Agana 115 kV lines. Prior to the construction of the Piti-Harmon 115 kV line, GPA's power system was at risk from severe overloads and cascading outages resulting from an occurrence of this single contingency outage.

From 1997 to the present, GPA experienced flat to declining growth in system peak demand due to the Asian Economic Crisis triggered in July 1997[1].[2] Guam's main economic driver depends upon tourism from Japan. Japan's long term economic malaise[3] has flattened out the Guam economy.

Figure 2-1 shows that GPA's system peaked at 281.5 MW in FY 2001. After FY 2002, system peak demand plunged to a low of 267 MW before recovering to 275 MW in FY 2006. After three successive years of sub-270 MW peak demand, peak demand is beginning to recover largely because of increasing DoD demand. GPA has experienced increases in the number of civilian sector customers. However, theses increases have come with declines in the average customer consumption contributing to flat or even declining civilian sales.

The FY 1997 LRTP considered designs to meet the requirements for much bigger power system demand increases than have transpired. For example the FY 1997 LRTP projected a gross peak system demand of 341.7 MW by 2009. The FY 2009 actual peak is 268 MW. Thus, the existing transmission infrastructure has sufficed for the 13 years between Long Range Transmission Plans. However, with the proposed DoD buildup including the transfer of 8,000 marines from Okinawa, GPA's system is poised for rapid near-term growth. Without the impetus of the DoD buildup, GPA's transmission and substation infrastructure would suffice to serve "normal" system growth.

The FY 1997 LRTP forecast organic uniform growth. Proposed DoD loads include large spot loads that will likely place greater demands on moving power from Cabras-Piti to the Central and Northern zones than had been foreseen by the 1997 forecast for the same system peak demand.

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[1] Public Broadcasting Service (PBS). *The Crash: Unraveling the 1998 Global Financial Crisis ... Is the Worst Over?* http://www.pbs.org/wgbh/pages/frontline/shows/crash/. (Accessed May 15, 2010)
[2] Public Broadcasting Service (PBS). T*he Crash:Timeline of the Panic.* http://www.pbs.org/wgbh/pages/frontline/shows/crash/etc/cron.html. (Accessed May 15, 2010)
[3] C. Fred Bergsten, Takatoshi Ito, and Marcus Noland. *No More Bashing: Building a New Japan-United States Economic Relationship.* The Peterson Institute for International Economics. 2001. ISBN paper 0-88132-286-5.

Officially, the target date for the Marines on Guam is 2014 greatly accelerating the need for new infrastructure. The service requirement for transient demand includes an Amphibious Ready Group and a nuclear carrier berthing may occur beyond FY 2015.

In FY 2008, GPA completed its Integrated Resource Plan (IRP). Guam PUC acceptance of the IRP has triggered a PUC mandate for fuel diversification and renewable energy acquisition. GPA will need to integrate renewable energy into its grid as a result.

GPA is currently soliciting for 80 MW of renewable energy with a target commissioning of an initial 40 MW within 30 months and another 40 MW block within 60 months. The IRP recommends another 40 MW renewable energy block each in FY 2018 and FY 2020. Thus, GPA must plan accordingly.

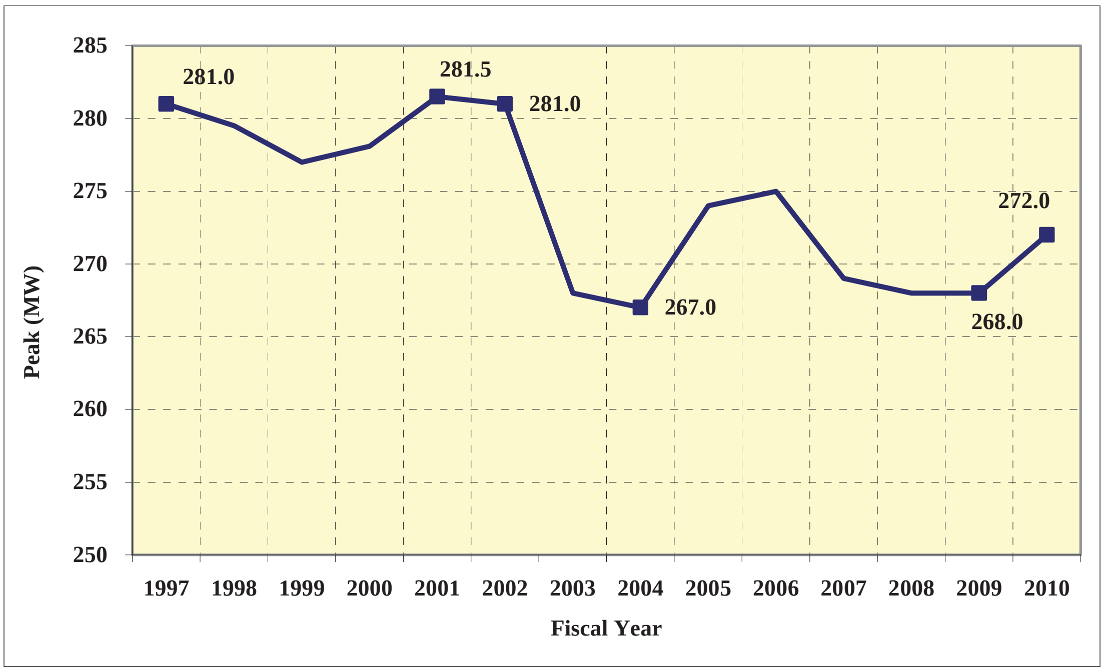


Figure 2-1, FY 1997 through FY 2010 Gross System Peak Demand

Figure 2-2 shows the IRP forecast for system gross peak demand. The lower green line in Figure 2-2 represents the “normal” system peak growth. The middle magenta line or baseline scenario represents the load growth scenario most likely representing the most recent information from DoD. The upper, dark blue line represents an explosive growth scenario with both an aggressive tourism and military economic expansion. The 2010 LRTP focuses on the developing plans for an update to the baseline scenario looking out at over a ten-year planning horizon. This updated forecast falls between the medium and high IRP forecast.

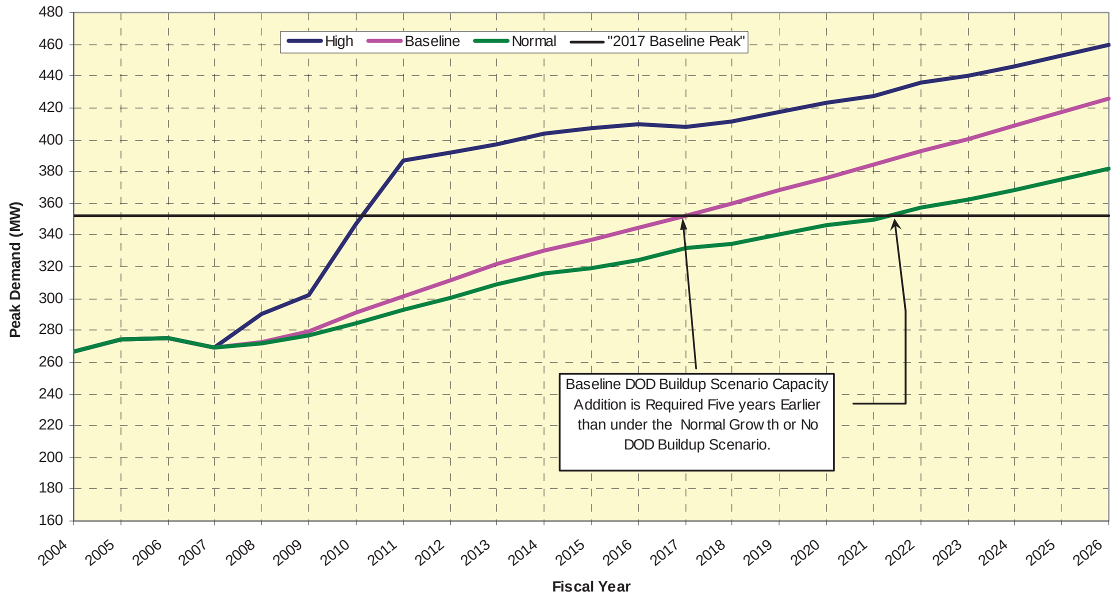


Figure 2-2, FY 2008 Integrated Resource Plan Peak Forecast Scenarios

GPA and the Joint Guam Program Office (JGPO) have had a continuing conversation regarding possible solutions to meeting DoD's new loads[4]. Many initial scenarios have been distilled to a single scenario[5]. JGPO presented GPA with the peak loading scenarios in Table 2-1. DoD advised GPA to assume a 0.8 power factor. As a note, the North Finegayan Substation must include a capability to back feed 2.35 MVA of existing load.

These proposed loads include transient and "fixed" loads. Orote and SRF Substation load additions under the Transient 1 group represent demand from an Amphibious Ready Group (ARG). Transient 2 load additions represent the load for a nuclear aircraft carrier (CVN) berthing at Polaris Point. Fixed Load additions are additions to peak DoD coincident demand without transient loads present. Transient 1 and 2 loads are mutually exclusive. Transient loads may occur on the annual peak or not. Therefore, there are three possible scenarios for peak system demand:

- The base peak demand without transient loads
- The base load peak demand plus Transient 1 loads
- The base load peak demand plus Transient 2 loads.

The DoD contribution at system peak in 2015 is projected as:

- 83.8 MW without transient loads
- 101.9 MW including Transient 1 loads
- 113.8 MW including Transient 2 loads.

[4] P.S. Lynch, Captain, CEC, USN, Commanding Officer NAVFACMAR. *Transmission & Distribution (T&D) Solutions for DoD Future Load Projections*. Document 1100 Ser 00/251 November 4, 2009.
[5] Conversations and email correspondence with Arlene M. Aromin, CIV USN NAVFACMAR

2.1 Existing Transmission System Description

GPA's existing transmission system differs greatly from 1997. Since then, GPA has completed the following Island Wide Transmission System (IWTS) capital additions 1997 Long Range Transmission Plan (LRTP) recommendations:

- Interconnection of the TEMES CT at 34.5 kV
- Interconnection of MEC 8&9 at 115 kV
- Construction of the Piti 115 kV switchyard in a breaker-and-one-half configuration
- Construction of the Cabras-Piti 115 kV line
- Construction of the Piti-Harmon 115 kV line
- Installation of the second Harmon 115/34.5 kV transformer addition
- Reconductoring of the 34.5 kV Piti-Orote Line to 927 MCM AAAC.

Table 2-1, DoD Buildup Loading Scenario

DoD Loads	Loads	Load Additions Type	DoD Scenario Loading (MVA)			
			Existing	3		
				Additions	Total	Backfeed
New North Ramp Substation	North	Fixed	-	10.22	10.22	
Existing Air Force Substation		Fixed	19.64	6.68	26.32	
Potts Junction Substation		Fixed	-	5.00	5.00	
North Finegayan Substation		Fixed	1.21	18.60	19.81	2.35
South Finegayan Substation		Fixed	-	10.46	10.46	
Orote Substation	South	Transient 1	22.30	12.70	35.00	
SRF Substation		Transient 1	5.70	9.78	15.48	
Cold Storage			5.00	-	5.00	
Polaris Point Substation		Transient 2	-	37.50	37.50	
North DoD Loads			20.85	50.96	71.81	2.35
South DoD Loads			33.00	59.98	92.98	-
Total			53.85	110.94	164.79	2.35
DoD Peak Without Transient Loads					104.81	
Transient 1 DoD Peak					127.29	
Transient 2 DoD Peak					142.31	

GPA has completed or will soon complete other system modifications:

- Dededo-Andersen Underground 34.5 kV Line
- Conversion of Harmon to Tanguisson 34.5 kV Overhead Line to Underground
- Conversion of Macheche to GAA 34.5 kV Overhead Line to Underground
- Replaced T-9 with 12 MVA transformer
- Replaced T-21 with TBD MVA transformer
- Converted Harmon to Tumon 34.5 kV Overhead Line to Underground
- Converted Tamuning to Tumon 34.5 kV Overhead Line to Underground
- Converted Harmon to Tanguisson 34.5 kV Overhead line to Underground
- Converted Harmon to San Vitores 34.5 kV Overhead line to Underground
- Converted Macheche to GAA 34.5 kV Overhead line to Underground

- Reconductored Harmon – GIAT to TBD
- Marbo to Pagat 34.5 kV Line (projected completion: 11/01/10).

DoD has completed or will soon complete these additional projects:

- P494: Cold Storage (New 20 MVA, estimated 2010 load = 10 MVA),
- Orote Substation (New 10 MVA, estimated 2010 load = 26 MVA total for substation)
- SRF Substation (New 20 MVA, estimated 2010 load = 15 MVA)

However, GPA has not completed the following 1997 LRTP recommendations:

- Putting 30 MW of load at Agana, Tamuning, and Macheche substations on under-voltage load shedding
- Compensating distribution power factor up to an average system power factor of 98%.

Appendix B and C include the FY 2009 115/34.5 kV Transmission One-Line Diagram and the FY 2009 GPA Transmission Island-Wide Power System Single-Line Diagram, respectively.

2.2 Existing System Power Factor

Average GPA System Power factor is below 98%. For example, at system peak on May 4, 2010, system power factor was 91.7%. Figure 2-3[6] illustrates how system power factor varied throughout May 4, 2010. GPA transmission system losses are on the order of 2.4%. This level of transmission system loss is not atypical. In relation to the 1997 system, Table 2-3 of the 1997 Long Range Transmission Plan indicates smaller losses for a larger peak load, as well as a system power factor of 95%.

[6] Power system power factor based on information provided by PSCC

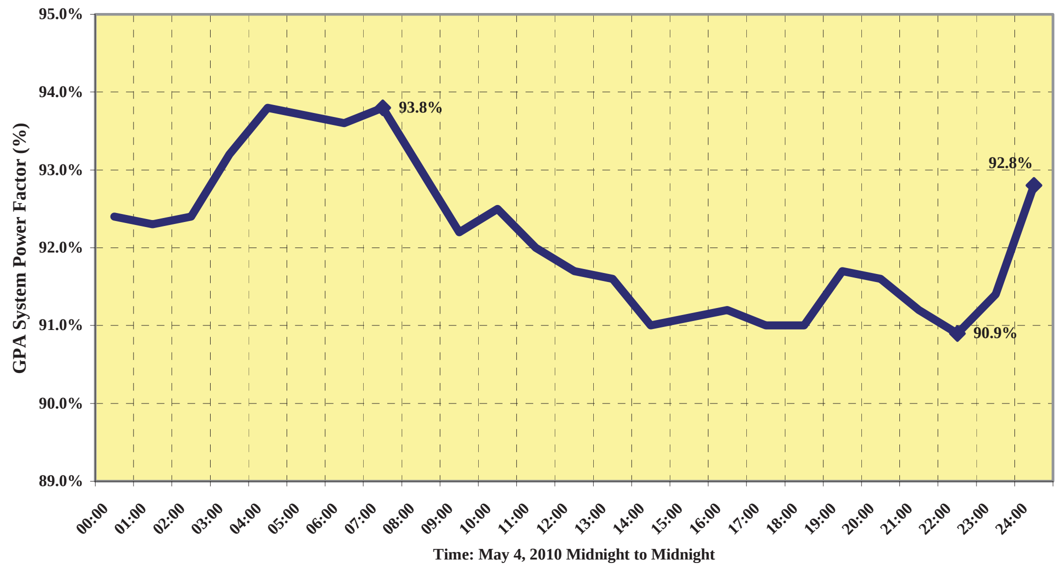


Figure 2-3, GPA System Power Factor throughout May 4, 2010 (251 MW System Peak)

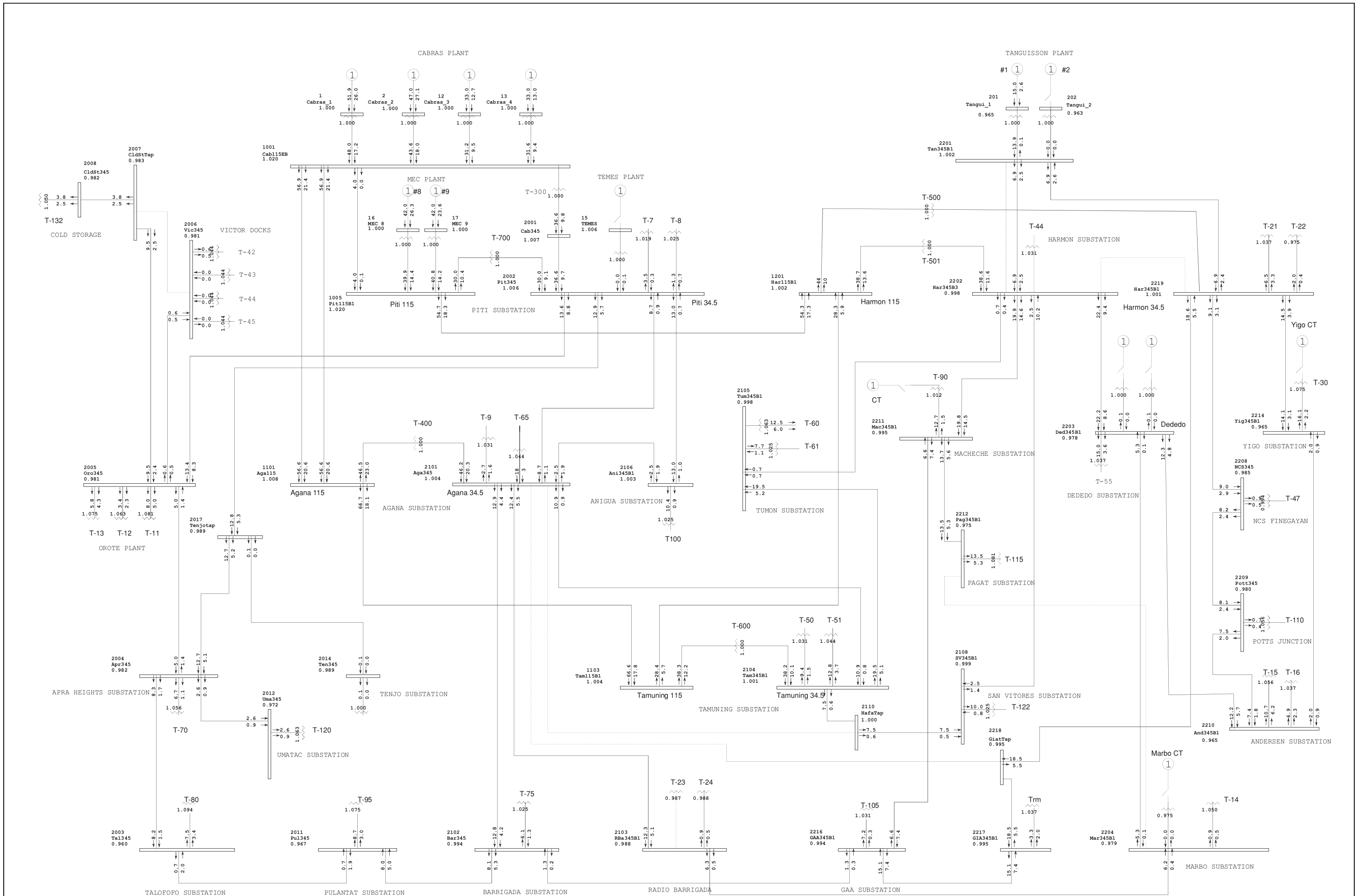
2.3 Existing Power System Power Flow

Figure 2-4 shows GPA's existing transmission one line with annotated power flow at FY 2009 system peak. In Figure 2-4, real power flow (MW) is indicated above the horizontal or to the right of vertical on the one line diagram. Reactive power flow is indicated below the horizontal and to the left of vertical. Arrows indicate the direction of power flow. Table 2-3 tabulates the power flows indicated in Figure 2-4.

In analyzing the GPA power system, it is illustrative to divide the island into three zones: Northern, Central, and Southern. Table 2-2 shows the substations serving each zone.

Table 2-2, GPA Transmission System Zone Summary

Zone	Zone Elements
Northern	Andersen Substation, Harmon Substation, Dededo Substation, NCS Finegayan, Macheche Substation, Marbo Substation, Marbo Tap, Potts Junction, Tanguisson Power Plant, Yigo Substation
Central	Agana Substaton, Anigua Substaion, Barrigada Substation, GAA Substation, GIAT Switching Station, Pagat Sustation, Radio Barrigada Substation, San Vitores Substation, Tamuning Substation, Tumon Substaion
Southern	Apra Substation, Cabras Substation, Cold Storage, Orote Plant (Substation), Polaris Point, Piti Substation, Pulantat Substation, Talofofo Substation, Tenjo Substation, Umatac Substation, Victor Docks



General Electric International, Inc. PSLF Program Tue May 11 17:00:56 2010 gpa2009-b.sav

Guam Power Authority Base Case Power Flow
Peak Load Case 5/8/07, last modified Jun 19, 2008 by Irwin
Original File: base2009a.sav

MW/MVAR
gpa-oneline-2009-base
Rating = 4

Figure 2-4, GPA Transmission One Line with Annotated Power Flow at FY 2009 System Peak

Table 2-3, FY 2009 IWPS Power Flow (268 MW Peak System Demand)

FROM	NAME	FKV	TO	NAME	TKV	CK	ST	P	Q	MVA	AMPS	%RATE	RATE	UNIT	PLOSS	QLOSS
1001	Cab115EB	115.00	1005	Pit115B1	115.0	1	-	3.5	-	3.5	17.5	1.5	1134.6	Amp	-	(0.04)
1001	Cab115EB	115.00	1101	Aga115	115.0	2	-	56.4	21.1	60.2	296.3	13.1	2274.3	Amp	0.24	0.82
1001	Cab115EB	115.00	1101	Aga115	115.0	1	-	56.4	21.1	60.2	296.3	13.1	2274.3	Amp	0.24	0.82
1005	Pit115B1	115.00	1201	Har115B1	115.0	1	-	54.3	18.1	57.2	281.7	25.0	1134.6	Amp	0.36	0.97
1101	Aga115	115.00	1103	Tam115B1	115.0	1	-	66.3	18.1	68.7	342.4	30.2	1134.6	Amp	0.09	0.30
1103	Tam115B1	115.00	1201	Har115B1	115.0	1	-	28.2	5.8	28.8	143.8	12.7	1134.6	Amp	0.04	(0.20)
2001	Cab345	34.50	2002	Pit345	34.5	1	-	36.6	9.7	37.8	628.2	27.8	2259.2	Amp	0.02	0.11
2002	Pit345	34.50	2101	Aga345	34.5	1	-	8.5	(1.1)	8.6	142.7	23.7	602.5	Amp	0.04	0.17
2002	Pit345	34.50	2106	Ani345B1	34.5	1	-	12.8	(0.9)	12.8	213.2	18.7	1138	Amp	0.06	0.26
2002	Pit345	34.50	2017	Tenjotap	34.5	1	-	12.8	5.7	14.0	233.0	20.5	1138	Amp	0.08	0.38
2002	Pit345	34.50	2007	CldStTap	34.5	1	-	13.4	5.4	14.5	240.9	40.0	602.5	Amp	0.19	0.41
2002	Pit345	34.50	2005	Oro345	34.5	1	-	13.5	8.8	16.1	268.1	23.6	1138	Amp	0.11	0.53
2003	Tal345	34.50	2004	Apr345	34.5	1	-	(7.8)	(1.5)	8.0	139.0	21.3	652.7	Amp	0.12	0.21
2003	Tal345	34.50	2011	Pul345	34.5	1	-	0.3	(1.9)	1.9	33.7	3.0	1138	Amp	-	(0.05)
2004	Apr345	34.50	2017	Tenjotap	34.5	1	-	(12.4)	(5.1)	13.4	228.6	20.1	1138	Amp	0.03	0.17
2004	Apr345	34.50	2005	Oro345	34.5	1	-	(4.9)	1.4	5.1	86.7	7.6	1138	Amp	0.01	0.02
2004	Apr345	34.50	2012	Uma345	34.5	1	-	2.6	0.9	2.8	47.0	4.2	1138	Amp	0.01	(0.05)
2005	Oro345	34.50	2007	CldStTap	34.5	1	-	(9.4)	(2.5)	9.8	166.4	27.6	602.5	Amp	0.01	0.02
2005	Oro345	34.50	2006	Vic345	34.5	1	-	0.6	0.5	0.8	13.1	2.2	602.5	Amp	-	-
2007	CldStTap	34.50	2008	CldSt345	34.5	1	-	3.8	2.5	4.6	77.5	12.9	602.5	Amp	-	-
2011	Pul345	34.50	2102	Bar345	34.5	1	-	(8.4)	(4.9)	9.7	167.5	14.7	1138	Amp	0.08	0.32
2014	Ten345	34.50	2017	Tenjotap	34.5	1	-	(0.3)	(0.1)	0.3	4.7	0.4	1138	Amp	-	-
2101	Aga345	34.50	2106	Ani345B1	34.5	1	-	(2.3)	2.0	3.1	50.9	4.5	1138	Amp	-	(0.01)
2101	Aga345	34.50	2102	Bar345	34.5	1	-	9.8	5.1	11.1	184.0	16.2	1138	Amp	0.04	0.14
2101	Aga345	34.50	2104	Tam345B1	34.5	1	-	11.2	1.2	11.2	186.9	16.4	1138	Amp	0.03	0.12
2101	Aga345	34.50	2103	RBa345B1	34.5	1	-	16.9	5.3	17.7	295.4	49.1	602.5	Amp	0.13	0.62
2102	Bar345	34.50	2216	GAA345B1	34.5	1	-	1.3	(0.2)	1.3	22.5	2.0	1138	Amp	-	(0.03)
2103	RBa345B1	34.50	2204	Mar345B1	34.5	1	-	4.2	0.9	4.3	73.4	12.2	602.5	Amp	0.02	0.01
2104	Tam345B1	34.50	2110	HafaTap	34.5	1	-	7.5	0.6	7.5	125.5	14.2	886.9	Amp	-	-
2104	Tam345B1	34.50	2105	Tum345B1	34.5	1	-	19.5	5.2	20.2	337.3	29.7	1138	Amp	0.03	(0.15)
2105	Tum345B1	34.50	2202	Har345B3	34.5	1	-	(0.7)	(0.6)	1.0	16.0	1.4	1138	Amp	-	(0.38)
2108	SV345B1	34.50	2110	HafaTap	34.5	1	-	(7.5)	(0.6)	7.5	125.6	11.0	1138	Amp	0.01	0.02
2108	SV345B1	34.50	2202	Har345B3	34.5	1	-	(2.5)	1.4	2.9	48.6	29.5	602.5	Amp	0.01	(8.88)
2201	Tan345B1	34.50	2219	Har345B1	34.5	1	-	6.9	(2.6)	7.3	122.7	10.8	1138	Amp	0.01	(0.22)
2201	Tan345B1	34.50	2202	Har345B3	34.5	1	-	7.0	2.3	7.3	122.2	10.7	1138	Amp	0.01	0.03
2202	Har345B3	34.50	2211	Mac345B1	34.5	1	-	18.1	14.6	23.3	390.4	34.3	1138	Amp	0.05	0.03
2202	Har345B3	34.50	2203	Ded345B1	34.5	1	-	23.9	9.2	25.7	429.9	37.8	1138	Amp	0.19	0.96
2203	Ded345B1	34.50	2204	Mar345B1	34.5	1	-	(4.2)	(0.9)	4.3	73.6	6.5	1138	Amp	-	-
2203	Ded345B1	34.50	2210	And345B1	34.5	1	-	11.8	5.1	12.9	220.0	25.6	886.9	Amp	0.12	(0.86)
2208	NCS345	34.50	2219	Har345B1	34.5	1	-	(9.3)	(2.8)	9.7	164.5	27.3	602.5	Amp	0.10	0.19
2208	NCS345	34.50	2209	Pott345	34.5	1	-	8.4	2.3	8.7	148.0	24.6	602.5	Amp	0.03	0.05
2209	Pott345	34.50	2210	And345B1	34.5	1	-	7.7	1.9	7.9	135.5	22.5	602.5	Amp	0.08	0.17
2210	And345B1	34.50	2214	Yig345B1	34.5	1	-	1.7	(0.8)	1.9	32.6	5.4	602.5	Amp	-	(0.01)
2211	Mac345B1	34.50	2216	GAA345B1	34.5	1	-	(8.4)	7.4	11.2	188.1	16.6	1138	Amp	-	(0.07)
2211	Mac345B1	34.50	2212	Pag345B1	34.5	1	-	13.7	5.6	14.8	248.9	21.9	1138	Amp	0.17	0.35
2214	Yig345B1	34.50	2219	Har345B1	34.5	1	-	(14.4)	(3.0)	14.7	255.0	42.3	602.5	Amp	0.36	0.79
2216	GAA345B1	34.50	2217	GIA345B1	34.5	1	-	(14.2)	7.0	15.8	265.9	30.1	886.9	Amp	0.01	(0.06)
2217	GIA345B1	34.50	2218	GiatTap	34.5	1	-	(17.5)	5.1	18.3	307.0	34.7	886.9	Amp	0.02	(0.06)
2218	GiatTap	34.50	2219	Har345B1	34.5	1	-	(17.6)	5.1	18.3	307.4	27.0	1138	Amp	0.11	(0.02)

It is useful to review transmission lines as sources and sinks of reactive power in power systems[7]:

- Overhead (AC) lines generate reactive power under light load since their production due to the line shunt capacitance exceeds the reactive losses in the line due to the line impedance. Under heavy load, lines absorb more reactive power than they produce.
- Underground (AC) cables always produce reactive power since the reactive losses never exceed the production because of their high shunt capacitance.

[7] Mats Larsson, *Coordinated Voltage Control in Electric Power Systems*. Lund: Lund University 2000. pg 34

The column headings P and Q in Table 2-3 indicate the real (MW) and reactive power (MVAR) flow. If the P or real power is negative, then the initiating end (FROM) is absorbing power from the terminal end (TO). If the P or real power is positive, then the initiating end (FROM) is exporting power to the terminal end (TO). Since "the average value of the active power is not zero means that the energy, in average, is flowing in a certain direction; therefore there is a net transfer of energy from one point of the network to another one."[8]

Likewise for Q or reactive power flow, a negative value indicates "absorbing" reactive power while a positive value indicates "exporting" reactive power. One needs to be careful as reactive power flow does not mean a net transfer of power from one point of the network to the other. Reactive power flows back and forth throughout the system. The sense of reactive power that we call Q is really the maximum of the instantaneous reactive power. "This quantity measures the maximum reactive energy that flows during a cycle and therefore one gets a good estimate of how much energy is moving through the circuit even if the average reactive power is zero."[9] The amplitude of reactive power is really a descriptor of the "effort" to transmit real power and push current through the network. The higher the value of Q relative to P indicates more "effort".

PLOSS is real power loss or electrical energy per unit time dissipated in the system as heat. QLOSS is treated as a "loss in reactive power [but] is not a real loss but rather a loss in the amplitude of the reactive power as no reactive energy is lost."[10] A negative QLOSS indicates a gain in amplitude of the reactive power at the terminal end of the line.

Table 2-4 contains the generation and net interchange summary for the Southern, Central, and Northern Zones. Note that transmission system losses with respect to net generation are 2.2%. The load power factor is 94.9%. The FY 1997 Study recommended compensating up to 98% PF.

2.3.1 Central Zone

The Central Zone includes the hub of commercial and large hotels. The 2000 U.S. Census indicated that about 39.6% of Guam residents resided in the Central Zone.

The Central Zone contains no GPA generation plants. No net generation comes from the Central Zone. However, Central Zone loads account for 35.9% of total system net send out at peak. The Central Zone absorbs about 53.2% or 94.7 MW of the power exported out of the Southern Zone. Additionally, it accounts for 21.0% of losses. The Central Zone load power factor is 96.9%. This is much higher than the total system power factor at the load of 92.4%. A comparison between the FY 1997 and Table 2-4 Zonal Interchange Summary information indicates that the Central Zone lost load.

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[8] R. Fetea. *Reactive Power: A Strange Concept?* Department of Electrical Engineering, University of Cape Town, South Africa. 2000. pg. 4
[9] Ibid pg. 5
[10] Ibid pg. 7

Table 2-4, FY 2009 Zonal Interchange Summary

2009 Zonal Interface Summary						
Zone No	**Zone Name**	**Units**	**Net Generation**	**Load**	**Net Interchange**	**Losses**
			On-Line	Power		
1	Southern	MW	247.4	65.6	179.0	2.83
		MVAR	108.6	31.8	50.0	29.86
2	Central	MW	-	93.5	(94.8)	1.22
		MVAR	-	25.3	(16.1)	1.88
3	Northern	MW	15.0	97.5	(84.2)	1.71
		MVAR	0.6	28.0	(33.9)	11.27
	Total	MW	**262.4**	**256.6**	**-**	**5.76**
		MVAR	**109.2**	**85.1**	**-**	**43.01**

Figure 2-4 and Table 2-3 indicate that 113.2 MW or about 63.2% of the power exported from the Southern Zone into the Central Zone flows through the two Cabras-Agana 115 kV lines. These lines comprise about two-thirds of the critical expressway power flows from Southern Zone Generation absorbed into Central Zone. It accounts for 35.3% of the total net interchange into GPA's load center in the Central and Northern Zones. Some of this power flows into the Northern zone and back into the Southern Zone through the 34.5 kV transmission lines. The Central Zone exports 28 MW of power into the Northern Zone through the Tamuning-Harmon 115 kV line. The Central Zone Exports 8.4 MW, 5.2 MVARs back into the Southern Zone from the Barrigada-Pulantat 34.5 kV line, The Central Zone also pushes 1.1 and 0.9 MVARS from the Piti-Agana 34.5 kV and Piti-Anigua 34.5 kV transmission lines into the Piti 34.5 kV substation.

2.3.2 Northern Zone

The Northern Zone serves DoD Facilities at Andersen Air Force Base, NCS Finegayan, Marbo, and Potts Junction. It also serves primarily Dededo and Yigo villages. In the 2000 Census, Dededo posted the largest residential population on Guam accounting for about 27.8% of total. The Northern Zone accounted for 40.3% of the Guam population in 2000. Several new residential subdivisions have arisen in the last few years in the Northern Zone indicating a strong potential for the region to increase its percentage of the civilian population. Furthermore, almost all DoD load increases by 2014 will occur in the Northern Zone.

The Northern Zone accounts for 30.4% or 168 MW of GPA generation plants. However, two-thirds of this generation is diesel-fired. Diesel fuel is substantially more expensive than residual fuel oil (RFO). Producing electrical energy using diesel-fired generation outside of peaking applications is not economic. Furthermore, Tanguisson Power Plant despite using RFO has a much less efficient heat rate. Displacing energy produced by the

Cabras-Piti baseloads with that produced by Tanguisson is not economic. In 2009, GPA typically dispatches one Tanguisson at 15 MW at system peak.

Northern Zone loads account for 37.0% of total generation net send-out at peak. The Northern Zone absorbs about 46.7% or 83.2 MW of the power exported out of the Southern Zone. Additionally, it accounts for 29.8% of losses. A comparison between the FY 1997 and Table 2-4 Zonal Interchange Summary information indicates that the Northern Zone gained load.

The Northern Zone load power factor is 95.6%. This is much higher than the total system power factor at the load of 92.4%.

Figure 2-4 and Table 2-3 indicate that 82 MW of power exported from the Southern and Central Zones into the Northern Zone flows through the Piti-Harmon and Tamuning-Harmon 115 kV lines. These lines are the critical expressway from Southern Zone Generation to GPA's load center in the Central and Northern Zones.

2.3.3 Southern Zone

The Southern Zone serves DoD Facilities at Big Navy including facilities at Orote, Piti, and Apra Harbor, and at Naval Magazine. The Southern Zone accounted for 20.0% of the Guam population in 2000. The major new loads at Southern DoD facilities include transient demand supporting an Amphibious Ready Unit at Orote and SRF and a nuclear carrier group at Polaris Point. These loads are mutually exclusive.

The preponderance of power supply on the GPA system originates from the southern zone. Appendix D lists GPA generation resources, their nameplate megawatt rating, zone location, operational type, and fuel-type. The Southern Zone generation comprises 69.6% of total GPA installed capacity. Of this generation, the Southern Zone RFO-fired generation comprises 299 MW or 84.9% of GPA's total 352 MW of RFO-fired capacity. Additionally, the Southern Zone has the best wind resources sites yet identified.

Southern Zone loads account for 24.9% of total generation net send-out at peak. The Southern Zone exports 178 MW of power to the Central and Northern Zones. Additionally, it accounts for 29.8% of losses. A comparison between the FY 1997 and Table 2-4 Zonal Interchange Summary information indicates that the Southern Zone maintained load.

Figure 2-4 and Table 2-3 indicate that 166 MW of power exported from the Southern Zone into the Northern and Central Zones flows through the Piti-Harmon and two Cabras-Agana 115 kV lines. These lines are the critical expressway from Southern Zone Generation to GPA's load center in the Central and Northern Zones.

2.4 Transmission System Performance and Design Drivers

Over the last several years, GPA has produced greater than 95 % of its energy from its residual fuel oil (RFO) baseload and intermediate baseload units. Under economic dispatch and optimal unit commitment, using Southern Zone generation greatly reduces electric power production costs. However, as demand increases, GPA expects northern generation production to increase to serve additional loads.

Table 2-5 shows the projected percent of energy production from FY 2010 through FY 2015 by fuel type and zone. This illustrates that sourcing of electric power from generation in the southern zone to the other zones will continue in the near term. Additionally, with the best wind resources in southern Guam, GPA needs to address transmission capability to bring renewable energy from wind farms to its central and northern loads.

The biggest design and transmission system performance driver is the fact that GPA preferred generation is predominantly in the Southern Zone while the load centers are in the Central and Northern Zones. The most critical elements of the GPA transmission system are the 115 kV lines along the Cabras-Piti to Harmon transmission corridor. Adding additional loads in the Northern Zone while installing and dispatching more generation in the Southern Zone additionally stresses the GPA transmission system whenever outages occur within this transmission corridor.

Aside from large Navy facilities and the Guam Port Authority, rural and sparse density residential customers comprise the Southern Zone. Thus, the preponderance of southern zone power system load is at Orote and Apra. Port expansion and the expansion of Navy facilities at Orote and Apra will likely drive upgrades to transmission facilities.

Table 2-5 Projected Sourcing of Energy Production by Zone and Fuel Type

Zone	Fuel Type	2010	2011	2012	2013	2014	2015
Northern	DSL	0.6%	1.0%	2.2%	1.5%	2.3%	2.2%
	RFO	4.4%	4.8%	6.3%	5.5%	5.9%	5.6%
Northern Total :		**5.0%**	**5.8%**	**8.5%**	**7.0%**	**8.1%**	**7.8%**
Southern	DSL	4.6%	5.9%	9.8%	8.4%	9.2%	8.9%
	RFO	90.4%	88.3%	81.7%	84.6%	82.7%	82.2%
	WIND	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%
Southern Total :		**95.0%**	**94.2%**	**91.5%**	**93.0%**	**91.9%**	**92.2%**

2.5 Existing System Performance Against Various Contingencies

GPA evaluates transmission system performance under the GPA Transmission Planning Criteria listed in Appendix E. These criteria include evaluating system performance under a set of single and double contingencies. Appendix F and G, respectively, list the single and double contingencies used in this study. FY 2009 transmission system performance under all single and double contingencies results in no planning criteria violations. This expected as the GPA transmission system was designed to accommodate much higher system peak loads while the FY 2009 system peak demand is much less than in FY 1996.

Section 3 Scope of Work

GPA should update the Long Range Transmission Plan every five years when demand growth is slow and predictable. It should update this plan every two years in the midst of high demand growth or major change in system load or in power supply occurs. In particular, the 2010 Long Range Transmission Plan (LRTP) focuses on:

- Determining transmission facilities requirements for supporting the planned DoD buildup
- Reviewing preliminary options for connection of planned renewable energy resources
- Reviewing potential for loss reductions by application of shunt capacitors.

The study determines the minimum capital expenditure requirement, and formulates robust alternative transmission system upgrade plans.

GPA defers the following for future studies:

- Determination of a detail undervoltage load scheme
- Modification of the underfrequency load shedding scheme
- Analysis of System Stability.

GPA's Generator Governor Tuning project is underway. One of the project outcomes is update all baseload unit machine models. Additionally, GPA's Renewable Energy Acquisition program requires that each proponent selected fund a System Impact Study to determine what measures of any must be taken to integrate renewable energy projects with the GPA power system grid. The underfrequency load shedding and system stability analysis studies should use these updated and new machine models.

Section 4 Key Assumptions

The key planning assumptions include:

- FY 2009 through 2020 planning period[1]
- The load forecast is based on GPA's load model from the FY 2008 Integrated Resource Plan (IRP) with updates based on current customer billing data and peak load readings. The load projections from the military have been added and replaced GPA's own military load projections.
  - DoD load additions conform to Scenario 3 found in NAVFACMAR's letter to GPA[2] (Appendix A)
  - Spot loads conform to those in Appendix H
- Renewable and conventional generation interconnection schedule as per Appendix I
- Generator retirement schedule as per Appendix J
- Completion of projects in Appendix K
- Future generation additions will interconnect with the grid at 115 kV
- Future generation additions at Cabras-Piti will use breaker and one-half arrangements
- GPA will continue its practice to construct new 115-kV and 34.5-kV overhead lines using 927 MCM AAAC conductor and new 34.5-kV underground transmission using 1000 MCM Aluminum cable
- Facility ratings as computed by FY 2010 GPA Bulk Electric Transmission System Facility Rating Methodology Handbook
- Project costs as per Appendix L
- All cost estimates are in 2010 dollars.

[1] This is in line with NERC Transmission Planning Standards such as TPL-001-0 through TPL-003-0, section R1.2.
[2] P.S. Lynch, Captain, CEC, USN, Commanding Officer NAVFACMAR. *Transmission & Distribution (T&D) Solutions for DoD Future Load Projections*. Document 1100 Ser 00/251 November 4, 2009.

Section 5 Analytical Methodology

5.1 Introduction

Planners chiefly identify questions that guide the process to finding the optimal solutions. Investing in capital and operations intensive solutions to the wrong questions often wastes resources and result in systems that are inadequate or grossly overbuilt. At each step in the planning process methodology, GPA must continually formulate questions until it can make prudent, satisfactory recommendations. This section with Appendix M may stand alone as a manual for long range transmission planning.

The requirements of the Plan stem from the fact that sound system planning is essential for the development of the GPA electric transmission system to quantify current and future requirements and to develop alternatives to effectively, economically, and reliably meet those requirements. The process provides for an orderly development of the system such that the new investment in facilities is in step with GPA and military load growth. Uncertainty related to timing and infrastructure requirements of the military load reinforce the need for careful system planning for transmission facilities. While the process is specific, transmission planning is dynamic and iterative, relying on numerous data inputs, assumptions, criteria and an understanding of the overall grid.

For this study, GPA uses standard industry load flow and transient stability software, along with several analytical techniques, to develop a detailed GPA transmission system model. The system models and cost estimates reflect existing system operating characteristics data and costs.

The analyses in these studies are based on load flows derived from the General Electric Positive Sequence Load Flow (PSLF) program. Although, in the past Long Range Transmission Studies, GPA investigated the dynamic behavior of the GPA system using the General Positive Sequence Dynamic Simulation (PSDS) program, GPA will study this behavior using new machine models arising from its Generator Tuning project. The computation of the electrical parameters of overhead transmission lines and underground cables is derived from the ASPEN Line Constants Program™.

Due to the diversity of the distribution load model, distribution substation overloads are not accounted for in this report. GPA has a distribution load flow program. GPA will handle distribution system studies separately.

Additionally, the study methodology addresses the following transmission infrastructure issues:

- Determining transmission facilities requirements for supporting the planned DoD buildup and civilian sector growth
- Reviewing preliminary options for connection of planned renewable energy resources
- Reviewing potential for loss reductions by application of shunt capacitors.

GPA analyzes existing transmission system and three expansion plans against a set of line and transformer outage contingencies. GPA determines this set from an initial analysis of the existing transmission system revealing basic potential problem areas.

GPA then reviews the transmission system performance of various alternate transmission expansion plans against its Transmission Planning Criteria. GPA identifies the least cost transmission expansion plan meeting its criteria. GPA will make recommendations regarding against the objectives of the work scope.

5.2 Planning Process Overview

Appendix M contains the Work Breakdown Structure (WBS) and Responsibility Assignment Matrix (RAM) for Long Range Transmission Planning. Figure 5-1 indicates the first level of tasks for this process:

- Spatial Forecast
- Determine Scope
- Planning Process Inputs
- Determine Key Assumptions
- Create and Validate Base Case
- Perform Situation Analysis
- Perform Preliminary Analysis
- Form Candidate Expansion Plans
- Evaluate Candidate Expansion Plans
- Determine Timing of Expansion Projects
- Economically Address System Losses
- Address System Stability
- Address Voltage Collapse Potential
- Perform Short Circuit Studies
- Determine Operational Considerations
- Craft Recommendations
- Determine Conclusions
- Create Executive Summary
- Peer Review and Finalizing Report.

Planners must perform literature searches for new methods, technologies, and issues affecting the power industry. Additionally, they should consult with operations personnel within GPA and among their industry contacts to scope for problems and issues. This work is performed throughout the planning process.

Figure 5-1, Long Range Transmission Planning Work Breakdown Structure (WBS)

5.2.1 Spatial Forecast

GPA performs transmission planning in anticipation of change. GPA's spatial load forecast projects the timing, distribution, and magnitude of changes in demand for electric power. The forecasting the magnitude of changes and the location or distribution of these changes in electric power demand anticipates:

- The magnitude and location of new loads
- The magnitude and location of areas of declines in load
- The characteristics of these new loads in terms of real and reactive power requirements.

Forecasting the timing of these changes allows better planning for resource allocation and project scheduling priority.

GPA system planning requires the following forecasts of demand and energy requirements:

- Long Range System Peak Demand and Sales Forecast/ Integrated Resource Planning Forecast (IRP)
- Long Range Substation Load Forecast
- Medium Range Distribution Load Forecast.

GPA uses the System Peak Demand and Sales Forecast in its Integrated Resource Planning process. The planning horizon for this forecast is twenty to thirty years. GPA uses the Long Range Substation Load Forecast for long range transmission planning. The planning horizon for this forecast is ten to fifteen years. GPA uses the Medium Range Distribution Load Forecast for medium range distribution planning. The planning horizon for this forecast is five years. The expectation is that the assets acquired as a result of the recommendations of these planning processes will be in service for at least the planning horizon. Additionally, these planning period horizons recognize that the higher the expected magnitude of costs, the greater the need for longer term planning.

GPA uses a consolidated approach to forecasting demand and energy requirements. This means that the Distribution Load Forecast aggregates to the Substation Long Forecast, which in turn aggregates up to the IRP Forecast. This ensures that there are common sets of assumptions and methods for these forecasts. Finally, this consolidated approach makes defending these forecasts easier.

GPA builds its spatial forecasts based on customer billing information including energy consumption, mapping specific customers to the distribution feeder serving them, customer class, customer class load shape characteristics, forecasts of growth by customer class (IRP Forecast), load data, and census information by geographical location. The feeder forecasts are aggregated to substation load forecasts.

For the FY 2010 Long Range Transmission Plan, GPA began with the IRP System Peak and Energy Sales Forecasts. The IRP Energy Sales Forecast (PL Mangilao / Kemm Farney, Phd.) projects the Energy Sales (kWh) by customer rate class. The IRP System Peak Forecast projects monthly and annual gross power system peaks. GPA used historical civilian customer energy consumption data from its Customer Information System (CIS) database and mapped each customer account to the distribution feeder serving that account. GPA also collected substation metering data. GPA then worked with P.L Mangilao to establish statistical relationships between the data sets used class coincident peak data from GPA's 1994 Load Research Study to build the peak transformer loads at system peak. Finally, GPA used future load projections provided by DoD[1]. These substation loads were aggregated into a total gross power system peak using losses information.

5.2.2 Determine Scope

GPA must determine what work it will perform based upon the immediate and near-term needs and resources. GPA must coordinate the work in coordination with other projects that may change power system performance. This scope begins as general questions that will guide the planning process.

5.2.3 Planning Process Inputs

Transmission planning requires many inputs from various sources:

- Load Forecasting
- Generation Resource Planning
- Facility Siting and Right-of-Way (ROW)
- System Operations
- Technical Projects/ T&D Construction/Engineering
- Transmission Planning
- Executive Management
- Legal and Regulatory.

Load forecasting provides the timing, distribution, and magnitude of changes in demand for electric power served through the substations.

Generation resource planning provides machine model data, generation operating information, generation economic dispatch, and proposed generation resource additions.

Facility Siting and Right-of-Way (ROW) information provides key input into the long-range concept plan regarding potential routes, substation locations and other land management issues.

System Operations (PSCC) provides key input regarding operational concerns, voltage control, voltage profiles, transformer taps and other issues regarding the short-term operation of the system.

Technical Projects/ T&D Construction/Engineering provide facility ratings for use in the Plan power flow cases. It provides a list of completed projects since the last transmission plan and a timeline for projects in the five-year CIP schedule. It also provides budgeting

[1] P.S. Lynch, Captain, CEC, USN, Commanding Officer NAVFACMAR. *Transmission & Distribution (T&D) Solutions for DoD Future Load Projections*. Document 1100 Ser 00/251 November 4, 2009.

information for substations, overhead and underground lines. This cost information is modified and utilized in evaluating Plan alternatives.

Transmission Planning:

- Acquires data necessary to perform Long-Range evaluation
- Creates the transmission long-range concept plan
- Performs Plan technical power flow, short circuit and stability analysis
- Completes the Long Range Transmission Plan report
- Provides regulatory support for communicating, filing, and defending the report and recommendations.

Executive Management provides approval for Plan and resulting capital budget items. Legal and Regulatory provides input into the regulatory and filing aspects of the Plan and files the Plan with the Guam Public Utilities Commission.

5.2.4 Determine Key Assumptions

Assumptions limit the size of the solution space by recognizing that there will be gaps in knowledge, expectations, and uncertainties. After an assessment of the inputs to the planning effort, GPA must determine the key assumptions that will frame the investigation.

5.2.5 Create and Validate Base Case

GPA selects system peak demand for the latest full fiscal year to build its power flow base case. There are several methods to validate the base case model against depending upon the availability of information:

- SCADA Real-time transmission system snap shot data
- System disturbance recordings
- Past validated power flow models.

Areas that need to be verified include:

- Transmission element ratings and parameters
- Thermal limits
- Completeness of model.

Transmission planners will often drive-by the entire transmission system to physically verify existing transmission system one-lines.

5.2.6 Perform Situation Analysis

Performing a situation analysis sets the context for all the rest of the investigation. It assists in gaining insight to the strengths and vulnerabilities of the system: a threats and opportunities assessment. It discusses the critical intermediate and final system load service states. It builds the case for performing the investigation, and helps identify areas for fruitful inquiry. It explores how the current system operates. It also determines the current vulnerabilities of the system, and how this may translate to future vulnerabilities.

The salient elements of the situation analysis include discussions of the following:

- Discussions in differences between the load growth expectations in the last transmission plan and the current situation
- How the projects recommended in the last plan perform against prior expectations
- How other planning studies and recommendations will affect the transmission system
- Description of existing system
- Changes in the current system from the last transmission plan including completed projects
- Planned generation, transmission and substation projects that GPA will complete within the planning horizon
- Current system operation and performance against transmission planning criteria
- Existing system power flow between transmission system zones
- Transmission System Performance and Design Drivers

5.2.7 Perform Preliminary Analysis

GPA performs a preliminary analysis of the transmission system in its terminal state without any changes in the transmission system infrastructure except for that already planned under the five-year CIP schedule. The terminal system state includes new loads and new generation served at expected locations in the system. GPA runs simulations for the system under its normal state and under the system contingencies called for by the transmission planning criteria. GPA assesses the line and transformer overloads to determine the weak areas of the system. GPA also examines system power factor and losses.

5.2.8 Form Candidate Expansion Plans

GPA assesses the line and transformer overloads, and examines system power factor and losses to determine different candidate system expansion plans to bring system performance within the transmission planning criteria. This process evaluates the constraints that inhibit the power system capability for power transfer from the generation sources to the system loads. These constraints include:

- Current (Thermal) Related Constraints
- Voltage Related Constraints
- Operation Related Constraints.

Review of the “Increasing Power Transfer Capability of Existing Transmission Lines”[2] is a worthwhile undertaking prior to forming candidate expansion plans.

Each plan shall set forth the following information with respect to the proposed facilities to the extent such information is available:

1. The size and proposed route of any transmission lines or location of each plant proposed to be constructed.
2. The purpose to be served by each proposed transmission line or plant.
3. The estimated date by which each transmission facility or generating resource will be in operation.
4. The characteristics of generating resource including the maximum power output measured in megawatts, MVAR capability and the type of fuel.
5. The plans for any new facilities shall include a power flow and stability analysis report showing the effect on the current electric transmission system.

5.2.8.1 Thermal (Current) Related Constraints

As part of the preliminary evaluation, GPA identifies line and transformer overloads in the load flow results under normal operations and for sets of N-1 and N-2 outage contingencies. This is because transmission system elements are constrained by thermal (current) limitations.

IEEE Standard 738-2006 defines the maximum allowable conductor temperature as the maximum temperature limit that is selected in order to minimize loss of strength, sag, line losses, or a combination of the above. Operating overhead transmission lines at greater than this operating temperature may result in unacceptable increase in transmission line conductor sags. This may result in conductor-to-ground and other NESC clearances violations. It may also resulting reduction of mechanical strength through annealing or softening of the individual conductors in the cable. In the extreme case, the cable may structurally fail. Additionally, operation at higher current results in higher ohmic losses in the cable.

“Conductor surface temperatures are a function of the following[3]:

a. Conductor material properties
b. Conductor diameter
c. Conductor surface conditions
d. Ambient weather conditions
e. Conductor electrical current.

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[2] Daconti, J.R.; Lawry, D.C.; , "Increasing power transfer capability of existing transmission lines," *Transmission and Distribution Conference and Exposition, 2003 IEEE PES* , vol.3, no., pp. 1004- 1009 vol.3, 7-12 Sept. 2003.

[3] Institute of Electrical and Electronics Engineers, Incorporated. *IEEE Std 738-2006, IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors*. IEEE: 2007. pg. 1.

"The first two of these properties are specific chemical and physical properties. The third may vary with time and be dependent upon ambient atmospheric conditions other than weather. The fourth, weather, varies greatly with the hour and season. The fifth, conductor electrical current, may be constant or may vary with power system loading, generation dispatch, and other factors."

Given a set of defined properties and conditions, the equations relating electrical current to conductor temperature may be used to:

- Calculate the conductor temperature when the electrical current is known
- Calculate the current that yields a given maximum allowable conductor temperature.

With all else constant, over sufficient time, the conductor temperature will reach equilibrium or steady state. The steady-state thermal rating yields the constant electrical current that would yield the maximum allowable conductor temperature for specified weather conditions and conductor characteristics.

The thermal response of a conductor to a step increase in current is not instantaneous. Figure 5-1 illustrates the time lag between the introduction of the step change and the conductor reaching the steady-state thermal rating. Operationally, utilities may allow lines to overload under short-term and long-term emergency limits to allow operational changes to be made to the system to alleviate the overloads. "Transmission lines are typically submitted to three thermal constraints: a normal operation rating, a long-term emergency rating (4 hours) and a short-term emergency rating (15 minutes)."[4]

Operating power transformers in excess of nameplate rating involves some degree of risk besides aging and long time mechanical deterioration of winding insulation including the risk of the transformer exploding catastrophically.[5]

There are several strategies for dealing with thermal (current) overload issues including but not limited to:

- Increasing the current-carrying capacity of transmission lines and substation equipment
- Up-rating voltage service (i.e. go from 34.5 kV to 115 kV)
- Adding new lines
- Creating appropriate operational strategies to alleviate the overloads before unacceptable damage occurs.

[4] Daconti, J.R.; Lawry, D.C.; , "Increasing power transfer capability of existing transmission lines," *Transmission and Distribution Conference and Exposition, 2003 IEEE PES* , vol.3, no., pp. 1004- 1009 vol.3, 7-12 Sept. 2003. pg. 1004.
[5] Institute of Electrical and Electronics Engineers, Incorporated. *IEEE Std C57.91-1995 - IEEE Guide for Loading Mineral-Oil-Immersed Transformers.* IEEE: 1996. pg. 3.

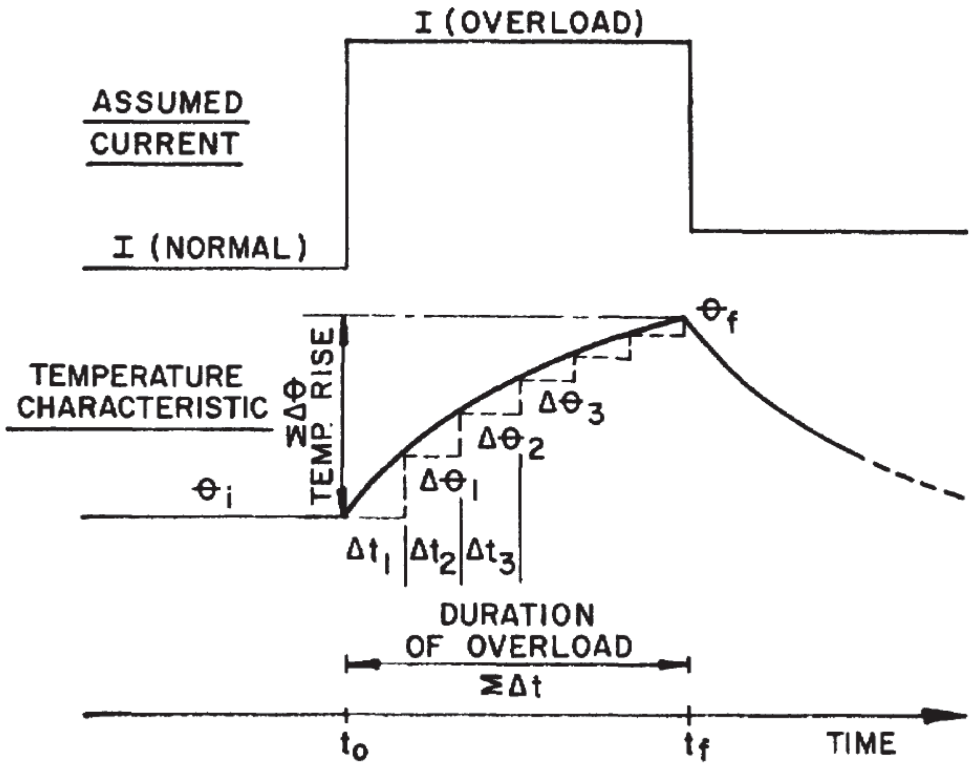


Figure 5-2, Response of Conductor Temperature to a Short-Time Overload[6]

5.2.8.2 Voltage Related Constraints

Steady-state over voltages may result in:

- Insulation failure
- Short-circuits
- Electromagnetic Interference.

Steady-state under voltages may result in:

- Inadequate operation of customers equipment
- Damage of motors.

There are several strategies for dealing with voltage issues including but not limited to:

- By increasing the operating voltage within a voltage class

[6] G. A. Davidson, T.T. Donoho, P.R.H. Landrieu, R.T. McElhaney, J.H. Saeger. *Short-Time Thermal Ratings for Bare Overhead Conductors*. IEEE Transactions on Power Apparatus and Systems, Vol. PAS-88, No. 3. IEEE: March 1969. pg. 195

- By controlling reactive power flows (reducing voltage drops)
- Up-rating voltage service (i.e. go from 34.5 kV to 115 kV).

5.2.8.3 Operation Related Constraints

Typical operation related constraints include but are not limited to:

- Power flow transfer between two areas can be limited by other parallel path flows
- Reserve capacity in terms of generation and transmission to handle contingencies
- Limits on active and reactive power transfers because of potential for transient instability, steady-state instability and voltage instability.

5.2.9 Evaluate Candidate Expansion Plans

GPA evaluates each candidate expansion plan for system performance under normal operation and system contingencies against the transmission planning criteria. GPA also evaluates the expansion plans against each other using net present net present value analysis of the benefits and costs to determine the best value expansion plan.

GPA typically uses these system studies to identify system deficiencies and support projects for the Plan.

1. General - In evaluating several alternative plans, comparisons of power flows, transient stability tests and fault levels are made first. After the alternatives are found to meet the system performance criteria in each of these three areas, comparisons may be made of the losses, transfer capability, impact on system operations and reliability of each of the plans. Finally, the costs of facility additions (capital cost items), costs of losses and relative costs of transfer capabilities are determined. A brief discussion of each of these considerations follows.

2. Power Flow Analyses - Power flows of base case (all lines in service) and single and selected double contingency conditions are tested and must conform to the system performance criteria set forth in Appendix E. Multiple contingencies beyond double may be examined, but, in general, no facilities are planned for such conditions.

   Normal system voltages, voltage deviations and voltage extreme limitations are based upon operating experience resulting in acceptable voltage levels to the consumer. Power flow limits are based upon the thermal ratings and/or sag limitations of conductors or equipment, as applicable.

3. Transient Stability Studies - Stability guidelines are established to maintain system stability for single contingency, three-phase fault conditions.

4. Short Circuit Studies - Three-phase and single-phase to ground fault studies are performed to ensure the adequacy of system protection equipment to clear and isolate faults.

5. Losses Analyses - A comparison of individual element and overall

transmission system losses are made for each alternative plan being studied. The losses computed in the power flow program consist of the I^2R losses of lines and transformers and the core losses in transformers where represented.

6. Economic Evaluation - In general, an economic evaluation of alternative plans consists of a cumulative present worth or equivalent annual cost comparison of capital costs.

As part of the FY 2010 Long Range Transmission Plan, GPA will perform items 1, 2, 5, and 6 above. GPA will perform items 3 and 4 after the completion of its Generation Tuning Project. For a large set of candidate expansion plans, GPA may perform items 3, 4, and 5 on a subset of “best” expansion plans.

5.2.10 Determine Timing of Expansion Projects

GPA may evaluate the best value expansion plan or a set of “best” plans to determine the timing of expansion plan projects. GPA will work backwards from the final plan state to optimize the timing of these projects with respect to year-to-year system requirements.

5.2.11 Economically Address System Losses

The concentration of generation at the southern end of the system while load is predominantly in the north causes highly inefficient supply of reactive power to these loads. The supply of higher levels of reactive power on the transmission system results in higher system losses and larger transmission system voltage drops. Alternately, the need for reactive power at the load is unavoidable. One way to mitigate the reactive flow is to compensate the load using distribution capacitors.

5.2.12 Address Transient System Stability

Determine fault clearing times for various fault locations to determine whether system stability issues exist for candidate expansion plan. Establish system stability guidelines to maintain system stability for single contingency, three-phase fault conditions.

5.2.13 Address Voltage Collapse Potential

Loss of 115 kV lines along the Cabras-Piti to Harmon transmission corridor cuts off power to the increasingly dominant load in Northern Zone. As the load increases in the Northern Zone, outages along this corridor may result in decreased reactive flow to the Northern Zone and increasingly severe voltage suppression. These conditions may result in over-excitation and overheating of generators and lead to tripping of automatic voltage regulators. When that occurs, system voltage may decay even further and lead to under-voltage protection tripping of the generators themselves. This is a form of voltage collapse. This task establishes the extent if any of candidate transmission plans to voltage collapse.

5.2.14 Perform Short Circuit Studies

Perform three-phase and single-phase to ground fault studies to ensure the adequacy of system protection equipment to clear and isolate faults.

5.2.15 Determine Operational Considerations

This task determines the changes in GPA operation to accommodate issues in each of the "best" candidate expansion plans. These operational considerations may save money over the addition of new transmission system elements. It may also allow GPA to defer the upgrade or replacement of older assets.

5.2.16 Craft Recommendations

The Plan will discuss the merits of each candidate expansion plan, and make recommendations on which plan GPA should execute on. It will also recommend specific modes of operation or the requirements for investigation into modes of operation to ameliorate system issues in operating the system under the recommended expansion plan.

5.2.17 Determine Conclusions

GPA will draw conclusions for future planning efforts and operational considerations.

5.2.18 Create Executive Summary

GPA will condense the information in the Plan for executive management and Consolidated Commission on Utilities high-level review

5.2.19 Peer Review and Finalizing Report

GPA will seek peer review of the draft plan prior to submitting it to the Consolidated Commission on Utilities and the Guam Public Utilities Commission for review and approval.

Section 6 Results Discussion

This section discusses the results for the following long range transmission study tasks:

- Perform Preliminary Analysis (Task 1.7)
- Form Alternative Expansion Plans (Task 1.8)
- Evaluate Alternative Expansion Plans (Task 1.9)
- Determine Timing of Expansion Projects (Task 1.10)
- Economically Address System Losses (Task 1.11)
- Address System Stability (Task 1.12)
- Address Voltage Collapse Potential (Task 1.13)
- Perform Short Circuit Studies (Task 1.14)
- Determine Operational Considerations (Task 1.15).

GPA will defer tasks 1.12, 1.13, and 1.14 until after completion of the Generator Tuning Project. GPA will not complete those tasks in this report.

6.1 Preliminary Analysis (Task 1.7) Results

Preliminary analysis begins with running a power flow case under the following conditions:

- System is at the system peak demand forecast for the end of the planning period
- Completion of all projects scheduled for completion within the planning period but with no further modification
- System is in the normal operating state.

If the power flow case solves, GPA investigates the system overloads and heuristically brainstorms likely system changes including additions and modifications that may alleviate these weaknesses in the system.

The near-term considerations are dominated by the DoD build-up both in the construction phase and the final marine relocation. Additionally, DoD transient loads may appear after FY 2015, but more likely later after 2017. These transient loads will tie into the grid at Orote/SRF and another at Polaris Point. The Orote/SRF transient load represents the berthing of an Amphibious Ready Group. The Polaris Point transient load represents the berthing of a Nuclear Carrier Group (CVN). These two transient loads are mutually exclusive. Without transient loads, the normal FY 2015 system peak is 385 MW. If the Nuclear Carrier Group (CVN) berthing occurs at system peak, then the transient 1 system peak demand is 415 MW. If the Amphibious Ready Group (ARG) berthing occurs at system peak, then the transient 2 system peak demand is 403 MW.

The system peak demand for FY 2020 also depends on the occurrence of these transient loads. Without transient loads, the normal system peak is 419 MW. If the Nuclear Carrier Group (CVN) berthing occurs at system peak, then the transient 1 system peak demand is

449 MW. If the Amphibious Ready Group (ARG) berthing occurs at system peak, then the transient 2 system peak demand is 437 MW.

GPA created sets of power flow cases comprised of the current transmission system with the completion of currently scheduled transmission system projects at the forecasted peak system demand and loads for FY 2020 in the normal operating state under economic dispatch of generation and several scenarios of wind dispatch. GPA observed the following system weaknesses:

1. Overloads of transmission lines
2. Overloads of substation transformers.

The FY2020 transmission system with no system improvements overloads transformer feeding into distribution loads. These transformers include:

- AganaT65 (118% loading)
- TumonT60 (123% loading)
- DededT55 (102% loading)
- NCS T47 (420% loading).

It is obvious without a power flow run that T47 at NCS will have a severe overload since its current loading is at 1.21 MVA, while DoD plans to increase this load by 30.26 MVA by 2014. GPA can alleviate these overloads by:

- Replacing these transformers with new transformers that can accommodate the increased loads
- Add an additional transformer in parallel with the existing one to share the new load
- Redistribute loads to other substations.

However, the transmission study scope does not include the determination of which method to use and selection of the recommended distribution system capital improvement projects. This is the purview of the medium range distribution study.

The FY 2020 transmission system with no system improvements under normal operation overloads the NCS-Harmon 34.5 kV line (153% loading).

Guided by its Transmission Planning Criteria, GPA analyzed the FY 2020 without system modifications power flow runs under scenarios of single and double contingencies. These scenarios included contingencies under base dispatch and baseload unit outages. Table 6-1 lists the results of these contingency runs indicating the line overloads and the triggering outage contingencies. Application of outage contingencies resulted in no transformer overloads. This means no normal ratings are exceeded for single contingencies (N-1), and no emergency rating (140% of normal rating) was exceeded for double (N-2) contingencies.

Table 6-1, FY 2020 without System Improvements – Outage Contingency Results

Line Overload	Outage Contingency
Aga115 to Tam115B1 #1 115 kV Line	Line Piti 115 115.0 to Harmn115 115.0 Circuit 1 & Agana 34.5 to 115 Tran
Aga345 to RBa345B1 #1 34.5 kV Line	Line Aga115 115.0 to Tam115B1 115.0 Circuit 1
	Line Aga345 34.5 to Bar345 34.5 Circuit 1
	Line Aga345 34.5 to Tam345B1 34.5 Circuit 1
	Line Agana 34 34.5 to Tamuning 34.5 Circuit 1 & Tamuning 34.5 to 115 Tran
	Line Agana115 to Tamuning 115.0 Circuit 1 & Agana to GIAT 34.5
	Line Bar345 34.5 to GAA345B1 34.5 Circuit 1
	Line Har345B1 34.5 to Yig345B1 34.5 Circuit 1
	Line Harmon-Andersen 34.5 & Harmon T501 Tran
	Line Mac345B1 34.5 to Pag345B1 34.5 Circuit 1
	Line Pit115B1 115.0 to Har115B1 115.0 Circuit 1
	Line Pit115B1 115.0 to Har115B15 115.0 & Harmon T501 Tran
	Line Piti 115 115.0 to Harmn115 115.0 Circuit 1 & Tamuning 34.5 to 115 Tran
	Line Tam115B1 115.0 to Har115B1 115.0 Circuit 1
	Line Tam345B1 34.5 to Tum345B1 34.5 Circuit 1
	Line Tamuning 34.5 to Tumon 34 34.5 Circuit 1 & Harmon 34.5 to 115 Tran2
	Line Tamuning 115.0 to Harmn115 115.0 Circuit 1 & Tamuning 34.5 to 115 Tran
	Line Yig345B1 34.5 to And345B1 34.5 Circuit 1
	Tran Har345B1 34.50 to Har115B1 115.00 Circuit 1 0.00
	Tran Tam345B1 34.50 to Tam115B1 115.00 Circuit 1 0.00
Ded345B1 to And345B1 #1 34.5 kV Line	Line Har345B1 34.5 to Yig345B1 34.5 Circuit 1
	Line Yig345B1 34.5 to And345B1 34.5 Circuit 1
Har345B1 to NCS345 #1 34.5 kV Line	All cases
Har345B1 to Yig345B1 #1 34.5 kV Line	Line Har345B3 34.5 to Ded345B1 34.5 Circuit 1
Har345B3 to Ded345B1 #1 34.5 kV Line	Line Aga345 34.5 to RBa345B1 34.5 Circuit 1
	Line Har345B1 34.5 to Yig345B1 34.5 Circuit 1
	Line Mac345B1 34.5 to Pag345B1 34.5 Circuit 1
	Line Yig345B1 34.5 to And345B1 34.5 Circuit 1
Mar345B1 to Pag345B1 #1 34.5 kV Line	Line Har345B3 34.5 to Ded345B1 34.5 Circuit 1
Pit345 to Aga345 #1 34.5 kV Line	Line Cabr 115 115.0 to Agana115 115.0 Circuit 1 & Agana 34.5 to 115 Tran
	Line Piti 115 115.0 to Harmn115 115.0 Circuit 1 & Agana 34.5 to 115 Tran
Pit345 to CldStTap #1 34.5 kV Line	Line Apr345 34.5 to Oro345 34.5 Circuit 1
	Line Apr345 34.5 to Tenjotap 34.5 Circuit 1
	Line Pit345 34.5 to Oro345 34.5 Circuit 1
	Line Pit345 34.5 to Polar345 34.5 Circuit 1
	Line Piti-Apra Heights 34.5 & Cabras-Piti 34.5 Line
	Line Piti-Orote 34.5 & Cabras-Piti 34.5 Line
Pit345 to Polar345 #1 34.5 kV Line	Line Piti-Apra Heights 34.5 & Cabras-Piti 34.5 Line
	Line Polar345 34.5 to Tenjotap 34.5 Circuit 1
Polar345 to Tenjotap #1 34.5 kV Line	Line Pit345 34.5 to Polar345 34.5 Circuit 1
Tam345B1 to HafaTap #1 34.5 kV Line	Line Tamuning 34.5 to Tumon 34 34.5 Circuit 1 & Harmon 34.5 to 115 Tran1
	Line Tamuning 34.5 to Tumon 34 34.5 Circuit 1 & Harmon 34.5 to 115 Tran2
Tan345B1 to Har345B1 #2 34.5 kV Line	Line Harmon-Andersen 34.5 & Harmon T501 Tran
	Line Pit115B1 115.0 to Har115B15 115.0 & Harmon T501 Tran
	Line Tan345B1 34.5 to Har345B3 34.5 Circuit 2
	Tran Har345B1 34.50 to Har115B1 115.00 Circuit 1 0.00
	Line Agana 34 34.5 to Tamuning 34.5 Circuit 1 & Tamuning 34.5 to 115 Tran
	Line Tamuning 34.5 to Tumon 34 34.5 Circuit 1 & Harmon 34.5 to 115 Tran1
	Line Tamuning 34.5 to Tumon 34 34.5 Circuit 1 & Harmon 34.5 to 115 Tran2
	Line Tan345B1 34.5 to Har345B1 34.5 Circuit 2
	Tran Har345B3 34.50 to Har115B1 115.00 Circuit 1 0.00
	Line Agana 34 34.5 to Tamuning 34.5 Circuit 1 & Tamuning 34.5 to 115 Tran
Yig345B1 to And345B1 #1 34.5 kV Line	Line Har345B3 34.5 to Ded345B1 34.5 Circuit 1

6.2 Form Candidate Expansion Plans (Task 1.8) Results

Based upon the preliminary analysis, GPA formed candidate expansion plans targeted at accommodating the new DoD loads in the Northern and Southern Zones. GPA created six sets of Northern Zone and four sets of Southern Zone candidate expansion projects. Appendix N lists these sets of candidate expansion plans.

6.3 Evaluate Candidate Expansion Plans (Task 1.9) Results

GPA and R.W. Beck ran combinations of cases in Appendix R for island-wide candidate expansion plans. The NorthF-SouthA2 plan exhibited the best system performance of all island-wide candidate expansion plans. GPA observed the following from the results of study cases:

1. The NorthF-SouthA2 plan upgrades will alleviate the projected thermal violations for N-1 contingencies for all dispatch scenarios (except full wind at 160 MW) with the exception of Agana-Radio Barrigada 34kV and Agana-Tamuning 115kV.
2. No voltage violations for N-1 contingencies.
3. Peak 2 (ARG) requires reconductoring of Piti – Cold Storage – Orote 34kV, Peak 1 (CVN) does not.
4. New Harmon - Anderson 115kV (with reconductoring of the 34kV) resolves thermal overloads in the North, new Harmon - Anderson U/G 34kV does not. A new Harmon-Andersen U/G 34.5 kV line will hog the load leaving the other lines leading into Andersen very lightly loaded unless a split bus arrangement is in place.
5. Piti - Harmon and Tamuning – Harmon 115kV N-2 results in some thermal violations and low voltages for the base dispatch. Dispatch in the north relieves violations. Interrupting GWA load using the Smart Grid Load Control Management System and dispatch in the north relieves violations.

The cost of this plan is between $60 million to $67 million depending on contingencies. The high-end plan (NA-SA) cost ranges from $89,355,000 to $98,587,500.

6.4 Determine Timing of Expansion Projects (Task 1.10) Results

GPA must put all the recommended projects in place prior to 2014 to support the DoD build-up requirements. The 1997 Long Range Transmission Study recommended a capital improvement program to support a system peak of 348 MW. The FY 2014 peak will exceed this. Figure 6-2 indicates transformers with expected loading in each fiscal year.

The following transformers are expected to overload within the study period:

- AganaT65 (prior to FY 2013)
- TumonT60 (prior to FY 2016)

- DededT55 (prior to FY 2013)
- NCS T47 (prior to FY 2011).

Table 6-2, Transformer Loading by Fiscal Year

LOCATION	TRANSFORMER	MVA_RT	MW_RT	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Agana	T-65	22	21	19.00	19.67	20.20	21.08	21.70	22.25	22.77	23.44	24.03	24.63	25.15
Agana	T-9	18	17	0.76	0.76	0.76	0.76	0.76	0.76	0.77	0.78	0.79	0.80	0.80
Andersen	T-15	20	19	11.23	11.78	12.34	12.92	13.49	13.64	13.78	13.97	14.13	14.30	14.45
Andersen	T-16	20	19	7.42	7.96	8.49	9.03	9.56	9.66	9.75	9.86	9.96	10.07	10.16
Anigua	T-100	30	29	10.72	11.16	13.69	14.20	14.56	14.88	15.18	15.57	15.92	16.26	16.57
Apra Heights	T-70	13	12	6.88	7.08	7.22	7.50	7.70	7.88	8.04	8.26	8.45	8.65	8.81
Barrigada	T-75	22	21	11.56	11.96	12.31	12.83	13.20	13.53	13.84	14.24	14.59	14.95	15.27
Cold Storage	T-132	6	6	3.79	3.79	3.79	3.79	3.79	3.83	3.86	3.91	3.95	3.99	4.03
Cold Storage	T-133	25	24	8.00	8.93	9.85	10.78	11.71	11.82	11.93	12.07	12.20	12.33	12.44
Dededo	T-55	22	21	16.56	16.95	17.23	17.83	18.25	18.62	18.95	19.41	19.81	20.21	20.55
GAA	T-105	30	29	8.63	8.96	9.21	9.58	9.85	10.09	10.31	10.59	10.84	11.10	11.33
GIAT	GIAT Trm	18	17	3.46	3.59	3.71	3.83	3.92	4.00	4.08	4.18	4.27	4.36	4.44
Harmon	T-21	30	29	6.57	14.88	19.75	20.05	20.25	20.43	20.61	20.84	21.04	21.24	21.41
Harmon	T-22	9	9	1.95	1.95	1.95	1.95	1.95	1.97	1.99	2.01	2.03	2.05	2.07
Macheche	T-90	28	27	13.05	13.60	13.92	14.54	14.97	15.35	15.71	16.18	16.59	17.01	17.37
Marbo	T-14	14	13	0.73	0.73	0.73	0.73	0.73	0.73	0.74	0.75	0.76	0.77	0.77
NCS	T-47	8	8	4.19	8.84	13.49	18.13	22.78	23.01	23.22	23.49	23.74	23.99	24.21
Orote	T-11	10	9	8.01	8.01	8.01	8.01	8.01	8.09	8.17	8.26	8.35	8.44	8.52
Orote	T-12	10	9	3.43	3.43	3.43	3.43	3.43	3.46	3.50	3.54	3.57	3.61	3.65
Orote	T-13	14	13	5.80	5.80	5.80	5.80	5.80	5.86	5.91	5.98	6.04	6.11	6.16
Pagat	T-115	30	29	13.71	13.79	13.79	14.19	14.45	14.69	14.89	15.19	15.44	15.69	15.89
Piti	T-7	8	8	3.64	3.77	3.88	4.05	4.16	4.26	4.36	4.48	4.60	4.71	4.81
Piti	T-8	8	8	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.38	1.40	1.41	1.42
Pots Junction	T-110	5	5	1.31	1.95	2.59	3.23	3.87	3.91	3.94	3.99	4.03	4.08	4.11
Pulantat	T-95	30	29	8.83	9.14	9.29	9.68	9.94	10.19	10.41	10.70	10.96	11.22	11.44
Radio Barrigada	T-23	8	8	0.50	0.58	0.66	0.74	0.82	0.83	0.84	0.85	0.85	0.86	0.87
Radio Barrigada	T-24	8	8	1.02	1.10	1.18	1.26	1.34	1.35	1.37	1.38	1.40	1.41	1.42
San Vitores	T-122	30	29	11.62	12.06	12.09	12.53	12.82	13.09	13.33	13.65	13.94	14.22	14.45
Talofofo	T-80	13	12	7.66	7.85	8.17	8.48	8.70	8.90	9.07	9.31	9.52	9.73	9.92
Tamuning	T-50	22	21	9.58	10.09	10.32	10.83	11.19	11.51	11.81	12.19	12.53	12.87	13.17
Tamuning	T-51	28	27	14.74	15.38	15.75	16.42	16.89	17.32	17.72	18.22	18.68	19.13	19.53
Tumon	T-60	22	21	18.34	19.07	19.24	19.91	20.36	20.77	21.16	21.66	22.10	22.53	22.91
Tumon	T-61	30	29	12.25	13.49	13.60	14.00	14.27	14.52	14.75	15.04	15.31	15.57	15.80
Umatac	T-120	30	29	2.66	2.75	2.79	2.91	2.99	3.06	3.12	3.21	3.28	3.36	3.42
Victor Docks	T-42	4	4	0.49	0.49	0.49	0.49	0.49	0.49	0.50	0.51	0.51	0.52	0.52
Victor Docks	T-43	2	2	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Victor Docks	T-44	4	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Victor Docks	T-45	4	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Yigo	T-30	30	29	16.37	17.90	18.17	18.78	19.20	19.57	19.90	20.37	20.77	21.17	21.51
Orote	T-10	14	13						10.20	10.20	10.20	10.20	10.20	10.20
SRF	T-900	25	24		7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80
AnderTNEW	AnderTNEW	20	19		1.64	2.05	2.73	4.09	8.18	8.18	8.18	8.18	8.16	8.16
Polar1	Polar2	20	19						15.00	15.00	15.00	15.00	15.00	15.00
Polar2	Polar3	20	19						15.00	15.00	15.00	15.00	15.00	15.00

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NET LOAD WITHOUT TRANSMISSION LOSS	276.41	310.62	329.68	346.72	361.73	412.47	418.43	426.23	433.16	440.11	446.15
ANNUAL GROWTH RATE	14.03%	12.38%	6.14%	5.17%	4.33%	14.03%	1.44%	1.86%	1.63%	1.60%	1.37%

SHADED AREA INDICATE OVERLOAD

6.5 Economically Address System Losses (Task 1.11) Results

The concentration of generation in the Southern Zone of the system while the preponderance of load is in the Central and Northern Zones causes the supply of real power to these loads less efficiently. The higher the flow of reactive power versus the delivery of real power results in greater current flow creating higher losses and in larger voltage drops. Utilities add shunt capacitors to compensate loads to increase load power factor. Load compensation brings substantial savings in transmission losses.

Table 2-4 (FY 2009) contains the generation and net interchange summary for the Southern, Central, and Northern Zones. Note that transmission system losses with respect to net generation are 2.19%. The load power factor is 94.9%. Bringing the load power factor to 98% would require the addition of 32.0 MVARs of capacitors. The 2009 is very similar to the FY 1996 system so the results are from the FY 1997 Study.

Based upon a 75% system load factor, the system loss factor[1,2] is 0.61875. The Average Production Cost (Fuel Only) is $109/MWh. Real losses are 0.63 MW. The Cost of System Losses[3] is $372,209 MW/year. Capacitor costs are on the order of $48,600/MVAR. The payback period is 5 years.

Table 6-3 shows the transmission losses for various system power factors as well as reactive load at these power factors for the 2020 system with improvements (NF-SA2). The difference in reactive load between these power factors are the amount of capacitors required to bring the system up to the higher power factor.

For the 2020 system with improvements (NF-SA2), Real losses are 1.59 MW. About 90 MVAR of capacitors is required to bring the load from 92.7% power factor to 98%. However, the reactive loss savings of 13.90 MVARs from Table 6-1 reduces this to about 76 MVARs. If the 32 MVARs of capacitors computed for the FY 2009 system are in place, the FY 2020 system would require only 44 MVARs of additional capacitors to bring the load power factor from 92.7 % to 98.0%. The payback period is 2.5 years.

Table 6-3, FY 2020 (NF-SA2) Transmission Losses Parameterized by Load Power Factor

449MW System Load

Power Factor	VAR Load	Diff	Cum	Loss(MW)	Diff	Cum	Loss(MVAR)	Diff	Cum
0.93	180.80	0.00	0.00	11.25	0.00	0.00	98.77	0.00	0.00
0.94	162.97	17.83	17.83	11.10	0.15	0.15	97.09	1.68	1.68
0.96	130.96	32.01	49.84	10.51	0.59	0.74	89.78	7.31	8.99
0.98	91.17	39.78	89.63	9.66	0.85	1.59	83.19	6.59	13.90
1.00	0.00	91.17	180.80	8.92	0.74	2.33	72.53	10.66	17.25

6.6 Determine Operational Considerations (Task 1.15) Results

GPA should explore using dynamic thermal ratings or use of high thermal limit cable on critical lines with the highest probability of overload. “The increases in [dynamic thermal] rating thereby achieved (3% to 30%) have led to significant savings in both capital and revenue costs of the 275 & 400 kV transmission system now owned and

[1] Loss Factor – 0.3 * System Load Factor + 0.7% * (System Load Factor)^2
[2] A.S. Pabla. “Electric Power Distribution” McGraw Hill. New York: 2005. pg 209.
[3] Cost of System Losses = 8760 hours * Loss Factor * Average Production Cost ($/MWh) * System Loss (MW)

operated by the National Grid company plc."[4] Appendix V provides a statistical treatment of Guam wind data from the Tiyan Weather Station from January 1, 1995 through April 30, 2010.

[4] Lee, S.T.; Hoffman, S. "Power delivery reliability initiative bears fruit," *Computer Applications in Power, IEEE* , vol.14, no.3, pp.56-63, Jul 2001. doi: 10.1109/MCAP.2001.952938

Appendix A: DoD Future Load Additions

DEPARTMENT OF THE NAVY
NAVAL FACILITIES ENGINEERING COMMAND MARIANAS
PSC 455, BOX 195
FPO AP 96540-2937

IN REPLY REFER TO:
11000
Ser 00/251
November 4, 2009

Mr. Joaquin C. Flores, PE
General Manager
Guam Power Authority
P.O. Box 2977
Hagatna, GU 96932-2977

Dear Mr. Flores:

SUBJECT: TRANSMISSION & DISTRIBUTION (T&D) SOLUTIONS FOR DOD FUTURE LOAD PROJECTIONS

Per our discussions on October 6, 2009, NAVFAC Marianas requests your assistance in conducting a power flow analysis on the projected load increase associated with the Military Build-up to determine if T&D improvements are necessary for the Island Wide Power Systems (IWPS). The projected power requirement scenarios enclosed are hereby provided for your use as a basis for the analysis. If improvements are necessary, request you provide a list alternatives based on reliability along with costs associated with those alternatives.

Should you need additional resources to complete this analysis, please respond with those requirements as soon as possible as the results of the analysis are needed for planning discussions with the Government of Japan later this month.

Should you need additional information, my point of contact for this matter is Ms. Arlene Aromin at Arlene.Aromin@fe.navy.mil or 339-6107. You may also contact LCDR Russell Pile at Russell.Pile@fe.navy.mil or 339-6986.

P. S. LYNCH
Captain, CEC, USN
Commanding Officer

Enclosure: DoD Loads for TD Analysis Scenarios

cc: OPS, DPRI, UEM
file

DoD Loads for T&D Analysis

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
New North Ramp Substation	1.71MVA	1.71MVA + 8.51MVA	1.71MVA + 8.51MVA	1.71MVA + 8.51MVA
Existing Air Force Substation	19.64MVA	19.64MVA + 6.68MVA	19.64MVA + 6.68MVA	19.64MVA + 6.68MVA
Potts Junction Substation	0.79MVA	X'former Capacity	X'former Capacity	X'former Capacity
North Finegayan Substation	1.21MVA +16.79MVA	1.21MVA + 16.79MVA	1.21MVA + (2.35 + 1.81)MVA + 16.79MVA	1.21MVA + (2.35 + 1.81)MVA + 16.79MVA
South Finegayan Substation *	10.46MVA	10.46MVA	10.46MVA	10.46MVA
Orote Substation	22.3MVA + (0 + 12.70)MVA	22.3MVA + (5 + 12.70)MVA	22.3MVA + (0 + 12.70)MVA	22.3MVA + (5 + 12.70)MVA
SRF Substation	5.7MVA + 9.78MVA	5.7MVA + 9.78MVA	5.7MVA + 9.78MVA	5.7MVA + 9.78MVA
Cold Storage	5.0MVA + 0MVA	5.0MVA + 5MVA	5.0MVA + 0MVA	5.0MVA + 5MVA
Polaris Point Substation	26.25MVA	26.25MVA	37.5MVA	37.5MVA
Population Growth				
Construction Workers				16.8MW (year 2014 peak)
Construction-Induced				6.7MW (year 2014 peak)
Operation-Induced				6.85MW (year 2014 peak)
				1.93MW (year 2014 peak)

Notes:

Existing* - include only the existing load of the 34.5kV/4.160KV substation and do not include the existing load pf the 13.8KV NCTS Critical Infrastructure.

Existing** - loads at Orote will be distrubuted to Orote, SRF, and Cold Storage.

Existing*** - include the existing load of the 34.5kV/4.160KV substation and the existing load of the 13.8KV NCTS Critical Infrastructure.

Notes:

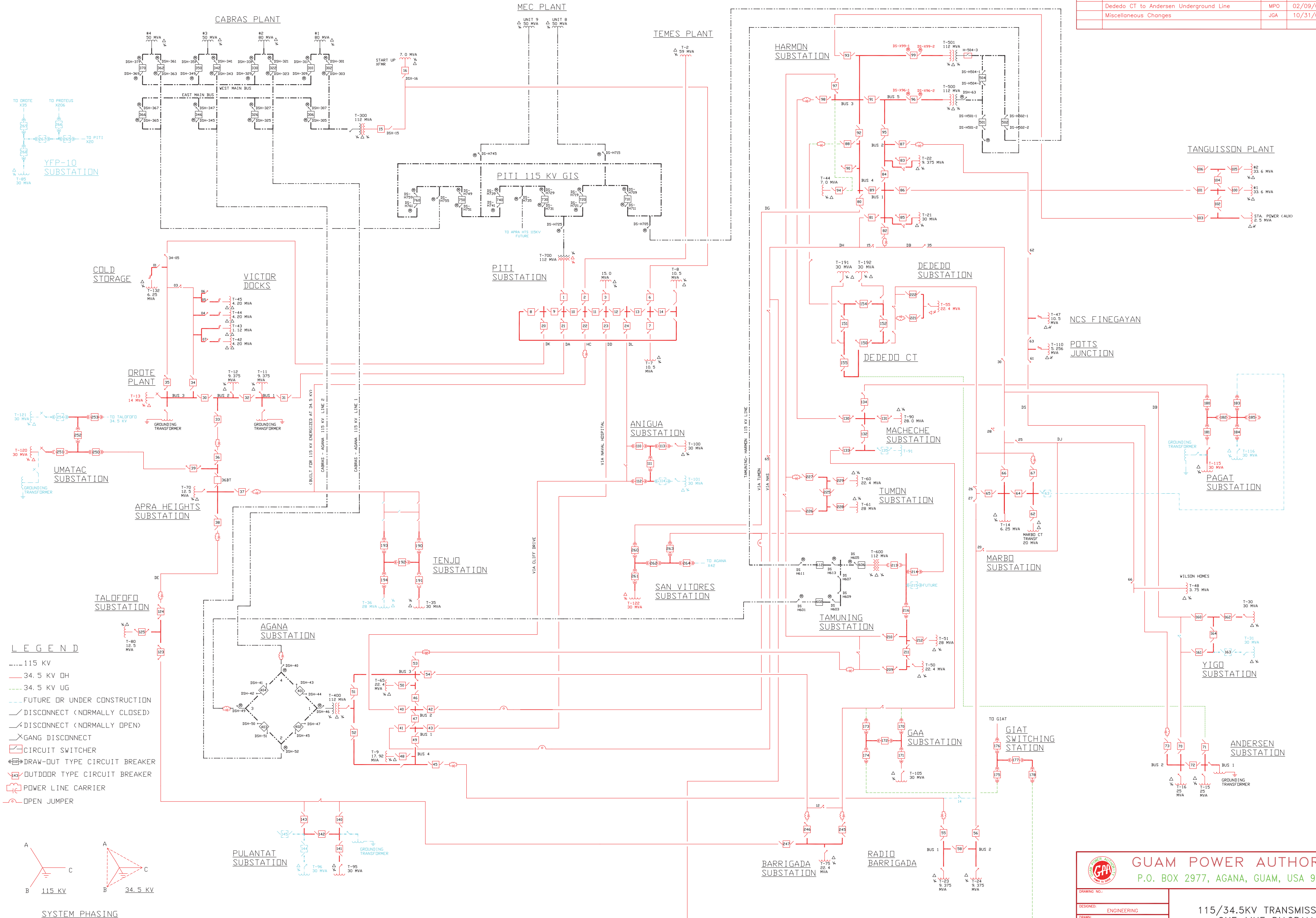
Existing load

Future 13.8kV back-feed capability

Appendix B- GPA Transmission One-Line

SYMBOL	DESCRIPTION	INT.	DATE	APP'D
	Harmon Substation Expansion and Misc. Changes	JLQ	5/30/02	JGA
	San Vitores/Orote/Andersen Mod. (Delete Proteus)	IBL	02/16/05	JGA
	Dededo CT to Andersen Underground Line	MPO	02/09/06	JGA
	Miscellaneous Changes	JGA	10/31/06	JGA

REVISIONS



GUAM POWER AUTHORITY

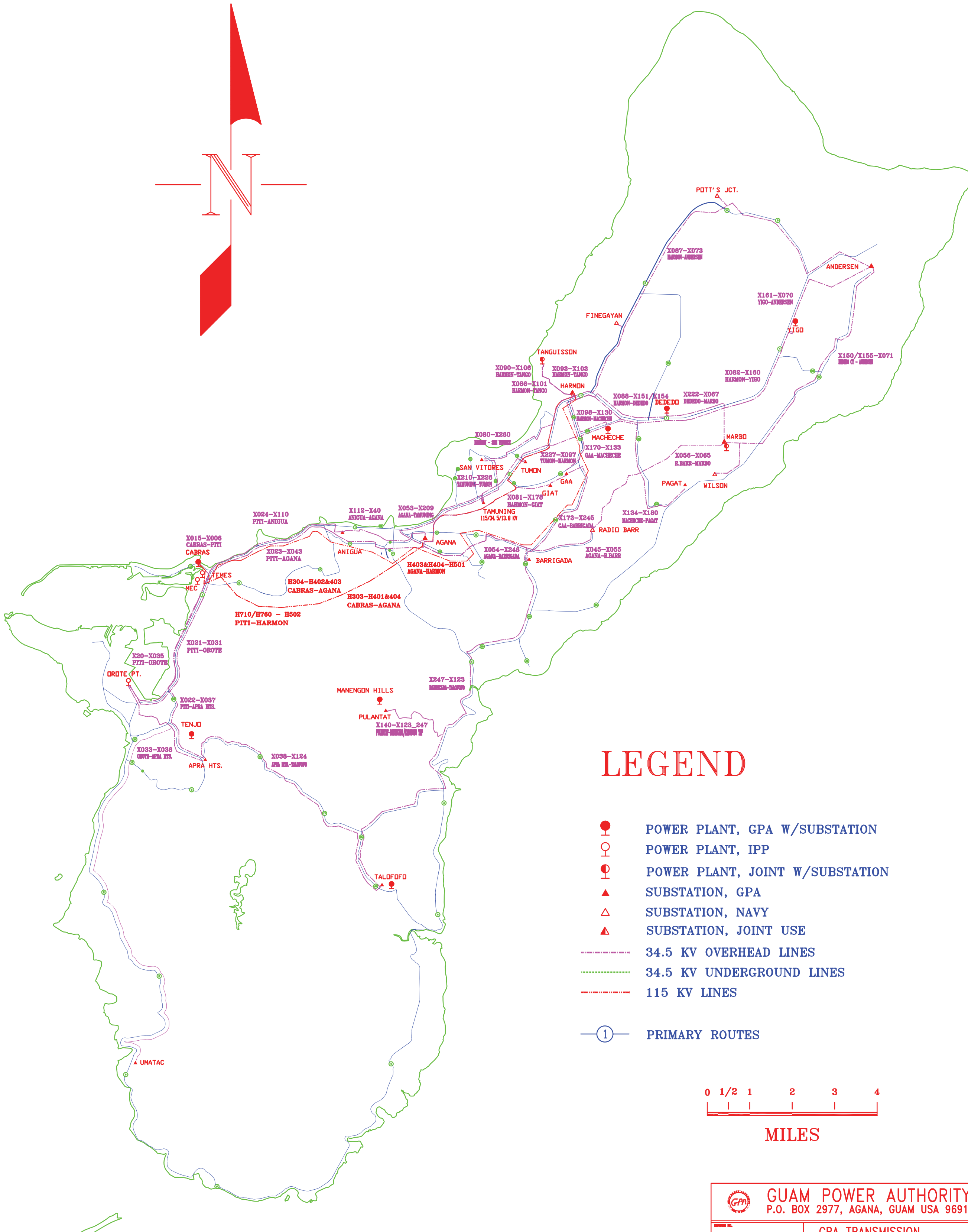
P.O. BOX 2977, AGANA, GUAM, USA 96910

115/34.5KV TRANSMISSION ONE-LINE DIAGRAM

DRAWING NO.:
DESIGNED: ENGINEERING
DRAWN:
CHECKED:
ENGINEERING SUPERVISOR-SUBSTATION: DATE:
MANAGER OF ENGINEERING: DATE:
JOB ORDER NO.:
GENERAL MANAGER:
SCALE: NOT TO SCALE
SHEET NO.: 1 OF 1
DATE:

DATE COMPLETED: October 31, 2006

Appendix C - Islandwide Generation Plants and Transmission One-Line



LEGEND

- POWER PLANT, GPA W/SUBSTATION
- POWER PLANT, IPP
- POWER PLANT, JOINT W/SUBSTATION
- SUBSTATION, GPA
- SUBSTATION, NAVY
- SUBSTATION, JOINT USE
- 34.5 KV OVERHEAD LINES
- 34.5 KV UNDERGROUND LINES
- 115 KV LINES
- 1 PRIMARY ROUTES

0 1/2 1 2 3 4

MILES

GUAM POWER AUTHORITY
P.O. BOX 2977, AGANA, GUAM USA 96910

DRAWING NO.	GPA TRANSMISSION ISLANDWIDE POWER SYSTEM SINGLE-LINE DIAGRAM
DESIGNED BY ENGINEERING	
DRAWN BY	
CHECKED BY	

	DATE	J.O. NO.	SCALE NTS	SHEET 1 OF 1
MANAGER OF ENGINEERING	DATE	GENERAL MANAGER		DATE

Appendix D: GPA Generation Resources

Unit	Year Unit Installed	Nameplate Capacity Rating	Primary Fuel	Zone	Zone Generation (MW)
Dededo C.T. #1	1992	23.0	Diesel	Northern	168.0
Dededo C.T. #2	1994	22.0	Diesel		
Dededo Diesel #1	1971	2.5	Diesel		
Dededo Diesel #2	1971	2.5	Diesel		
Dededo Diesel #3	1971	2.5	Diesel		
Dededo Diesel #4	1971	2.5	Diesel		
Macheche C.T.	1993	22.0	Diesel		
Marbo C.T.	1995	16.0	Diesel		
Tanguisson #1	1971	26.5	RFO		
Tanguisson #2	1973	26.5	RFO		
Yigo C.T.	1993	22.0	Diesel		
Cabras #1	1974	66.0	RFO	Southern	384.8
Cabras #2	1975	66.0	RFO		
Cabras #3	1995	39.3	RFO		
Cabras #4	1996	39.3	RFO		
Manenggon #1 (MDI, aka Pulantat)	1994	5.3	Diesel		
Manenggon #2 (MDI, aka Pulantat)	1994	5.3	Diesel		
MEC #8	1999	44.2	RFO		
MEC #9	1999	44.2	RFO		
Talofofo #1	1993	4.4	Diesel		
Talofofo #2	1993	4.4	Diesel		
TEMES	1998	40.0	Diesel		
Tenjo #1	1993	4.4	Diesel		
Tenjo #2	1993	4.4	Diesel		
Tenjo #3	1993	4.4	Diesel		
Tenjo #4	1993	4.4	Diesel		
Tenjo #5	1993	4.4	Diesel		
Tenjo #6	1993	4.4	Diesel		
Total Installed Capacity (MW)		**552.8**			**552.8**

Appendix E: Guam Power Authority Transmission Planning Criteria

I. Purpose

The purpose of these planning criteria is to establish guidelines for planning a reliable transmission system for the island of Guam.

II. Scope

The transmission system is defined as all substation equipment, lines, structures, and land utilized for transporting power at 34.5 kV and above

III. Contingency Criteria

The transmission system shall be planned on the basis of serving the forecasted peak demand on any part of the system each year for the following contingencies:

A. With any generating unit out of service, no NORMAL voltage and transmission element loading limits shall be exceeded for any of the following outages:

1. Any transmission circuit
2. Any transmission circuits sharing a common pole in a vertical configuration.
3. Any transmission power transformer.

B. With any generating unit out of service, no EMERGENCY voltage and transmission element loading limits shall be exceeded for any of the following outages:

1. Multiple transmission circuits due to structure failure.
2. Any transmission circuit and any transmission power transformer.

C. Each single generating plant should be able to export power equal to the sum of the individual generating unit(s) maximum capability ratings in MW with no transmission system component loading exceeding its normal rating, nor will voltage levels violate their upper or lower limits for any of the following outages:

1. Any transmission circuit.
2. Any transmission circuits sharing a common pole in a vertical configuration.
3. Any transmission power transformer.

D. For any three phase fault cleared in primary clearing time, the system will maintain synchronism with no loss of load or system generation due to over or under frequency.

E. For loss of any generating unit except Cabras Units 1 & 2, no underfrequency load shedding will occur.

IV. Voltage and Transmission Element Loading Limits

A. Normal Limits

1. **Voltages:** shall be with +/-5.0 percent of nominal ratings

2. **Transmission Power Transformer:** loading limit shall be its zero percent loss-of-life kVA capability.

3. **Transmission Lines:** The overhead and underground conductor ratings shall be as per GPA Engineering Standards.

B. Emergency Limits:

1. **Voltages:** shall be within +/-10.0 percent of nominal ratings.

2. **Transmission Power Transformer**: loading limit shall be its one percent loss-of-life kVA capability (approximately 140 % Normal Limit for four hours).

3. **Transmission Lines:** The overhead and underground conductor ratings as per GPA Engineering Standards.

Appendix F - Single Contingency Outages

Single Contingencies:

A single contingency is the outage of only a single transmission element such as a line or transformer. The following is a list of the single contingencies accounted for in the transmission analysis:

- **Cabras-Piti 115kV Line**
- **Cabras-Agana 115kV Line 1**
- **Cabras-Agana 115kV Line 2**
- **Piti-Harmon 115kV Line**
- **Agana-Tamuning 115kV Line**
- **Tamuning-Harmon 115kV Line**
- **Cabras-Piti 34.5kV Line**
- **Piti –Polaris 34.5kV Line**
- **Polaris-Tenjo Tap 34.5kV Line**
- **Piti –Orote 34.5kV Line**
- **Piti –Agana 34.5kV Line**
- **Piti –Anigua 34.5kV Line**
- **Talofofo –Apra 34.5kV Line**
- **Apra-Orote 34.5kV Line**
- **Apra-Umatac 34.5kV Line**
- **Apra-Tenjo Tap 34.5kV Line**
- **Orote-Victor 34.5kV Line**
- **Orote-SRF 34.5kV Line**
- **Orote-Cold Storage Tap 34.5kV Line**
- **Victor- Cold Storage Tap 34.5kV Line**
- **Piti- Cold Storage Tap 34.5kV Line**
- **Cold Storage Tap- Cold Storage 34.5kV Line**
- **Pulantat-Talofofo 34.5kV Line**
- **Pulantat-Barrigada 34.5kV Line**
- **Tenjo-Tenjo Tap 34.5kV Line**
- **Agana-Barrigada 34.5kV Line**
- **Agana-Radio Barrigada 34.5kV Line**
- **Agana-Tamuning 34.5kV Line**
- **Agana-Hafa Adai Tap 34.5kV Line**
- **Barrigada-GAA 34.5kV Line**
- **Radio Barrigada-Marbo 34.5kV Line**
- **Marbo –Pagat 34.5kV Line**
- **Pagat-Radio Barrigada 34.5kV Line**
- **Tamuning-Tumon 34.5kV Line**
- **Tamuning- Hafa Adai Tap 34.5kV Line**
- **Hafa Adai Tap-San Vitores 34.5kV Line**
- **Tumon-Harmon 34.5kV Line**
- **Anigua-Agana 34.5kV Line**

- **San Vitores-Harmon 34.5kV Line 1**
- **San Vitores-Harmon 34.5kV Line 2**
- **Tanguisson-Harmon B1 34.5kV Line 1**
- **Tanguisson-Harmon B1 34.5kV Line 2**
- **Tanguisson-Harmon B3 34.5kV Line 1**
- **Tanguisson-Harmon B3 34.5kV Line 2**
- **Harmon-Dededo 34.5kV Line**
- **Dededo-Anderson 34.5kV Line**
- **Harmon-NCS 34.5kV Line**
- **Harmon-Macheche 34.5kV Line 1**
- **Harmon-Macheche 34.5kV Line 2**
- **Harmon-Yigo 34.5kV Line**
- **Dededo-Marbo 34.5kV Line**
- **NCS-Potts Junction 34.5kV Line**
- **Potts Junction-Anderson 34.5kV Line**
- **Macheche-Pagat 34.5kV Line**
- **Macheche-GAA 34.5kV Line 1**
- **Macheche-GAA 34.5kV Line 2**
- **Yigo-Anderson 34.5kV Line**
- **GAA-GIA 34.5kV Line**
- **Giat Tap-GIA 34.5kV Line**
- **Giat Tap-Harmon 34.5kV Line**
- **Giat Tap-Agana 34.5kV Line**
- **Talofofo-Wind 34.5kV Line**
- **Apra-Wind 34.5kV Line**
- **SSD-Piti 115kV Line**
- **SSD-Cabras 115kV Line**
- **SSD-CLNG 115kV Line**

- **Cabras Transformer (T-300)**
- **Piti Transformer (T-700)**
- **Agana Transformer (T-400)**
- **TamuningTransformer (T-600)**
- **Harmon Transformer (T-501)**
- **Harmon Transformer (T-500)**

Appendix G - Double Contingency Outages

Double Contingencies:

A double contingency is the simultaneous outage of two transmission elements such as a line or transformer. The following is a list of the double contingencies accounted for in the transmission analysis:

- **Cabras-Agana 115kV Line and Circuit 1&2**
- **Agana-Tamuning 115kV Line and Agana-GIAT 34.5kV Line**
- **Cabras-Agana 115kV Line and Agana T400 Transformer**
- **Cabras-Piti 115kV Line and Agana T400 Transformer**
- **Piti-Harmon 115kV Line and Agana T400 Transformer**
- **Piti-Harmon 115kV Line and Tamuning T600 Transformer**
- **Agana-Tamuning 115kV Line and Tamuning T600 Transformer**
- **Tamuning-Harmon 115kV Line and Tamuning T600 Transformer**
- **Piti-Agana 34kV Line and Agana T400 Transformer**
- **Agana-Tamuning 34.5kV Line and Tamuning T600 Transformer**
- **Tamuning-Tumon 34kV Line and Harmon T500 Transformer**
- **Tamuning-Tumon 34kV Line and Harmon T501 Transformer**
- **Piti-Harmon 115kV Line and & Tamuning-Harmon 115kV Line**
- **Piti-Harmon 115kV Line and Harmon T501 Transformer**
- **Harmon-Andersen 34.5kV and Harmon T501 Transformer**
- **Piti-Orote 34.5kV Line and Cabras-Piti 34.5kV Line**
- **Piti-Apra Heights 34.5kV Line & Cabras-Piti 34.5kV Line**

Appendix H - Projected Spot Loads

PROJECT NAME	LOAD (KVA)	LOAD (MW)	LOCATION	FEEDER	SUBSTATION TRANSFORMER	RATE SCHEDULE	Assigned Year
Sasayjan Subdivsion	275	0.22	Mangilao	P-323	T-115	R	2010
Tonko Reyes (Paradise Estates Phase II and III)	1600	1.28	Dededo	P-089	T-55	R	2010
Gun Beach Condominium	6000	4.8	Tumon	P-111	T-21	R	2012
Talo Vista Tower and Commercial Center (Formerly Acanta Condominium)	1600	1.28	Tumon	P-243	T-61	P	2010
Ypao Beach Condominium	1600	1.28	Tumon	P-402	T-122	R	2010
Ypao Beach Condominium	1600	1.28	Tumon	P-241	T-60	R	2010
Acanta Mall Expansion	600	0.48	Tumon	P-403	T-122	P	2010
Outrigger Hotel Tower	4000	3.2	Tumon	P-243	T-61	P	2010
Tumon View Condominiums and Shopping Center (Across Holiday Inn)	6000	4.8	Tumon	P-242	T-60	P	2010
Younex Corp. (Next to GMH)	2000	1.6	Tamuning	P-203	T-51	R	2010
Younex Corp. (Next to GMH)	2000	1.6	Tamuning	P-401	T-122	R	2010
Ypao Beach Condominiums, 32 Units +14 (Del Carmen)	250	0.2	Tumon	P-402	T-122	R	2010
Ypao Beach Condominiums, 32 Units +14 (Del Carmen)	250	0.2	Tumon	P-241	T-60	R	2010
Garden Villa Redevelopement Condo 94 Units + 3 Story Retail Space (Across Fiesta Resort)	1100	0.88	Tumon	P-242	T-60	R	2010
Chichirica Estates Next to Pia Resort behind Duty Free 10 Units	300	0.24	Tumon	P-243	T-61	R	2010
Pago Bay Subdivision	500	0.4	Pago Bay	P-262	T-80	R	2010
Harmon Cliffline Housing	10000	8	Harmon Cliffline	P-112	T-21	R	2011
Housing Subdivision (Across Yigo Church)	1500	1.2	Yigo	P-331	T-30	R	2011
Housing Subdivision (Tallafofo - As Lucas)	200	0.16	Tallofofo	P-261	T-80	R	2012
Perez Bros	1500	1.2	Barrigada	P-311	T-105	R	2010
Adelup Saban, LLC Condominium	2800	2.24	Adelup	P-280	T-100	P	2012
Black Construction Worker Housing	1000	0.8	Harmon	P-245	T-61	R	2011

Appendix I - Generation Interconnection Schedule

	Generation Addition Description	Year In Service	Bus	Max Net Capacity (MW)	Min Net Capacity (MW)
1	Wind Farm #1	2011	9005	40	0
2	Wind Farm #2	2012	9010	40	0
3	Wind Farm #3	2018	9015	40	0
4	Wind Farm #4	2020	9020	40	0
5	Reciprocating Engine Plant (2x20 MW S/MSD) #1	2017	9025	40	10

Appendix J - Generator Retirement Schedule

Generator Retirements	
Unit	**Retirement Year**
DED DSL 1	2016
DED DSL 2	2016
DED DSL 3	2016
DED DSL 4	2016

Appendix K - Transmission System Project Completion Schedule

	Transmission Lines				
	Description		**Year In Service**	**From Bus**	**To Bus**
1	Conversion of Harmon to Tanguisson 34.5 kV Overhead Line to		2009		
	a. Circuit 1			2201	2219
	b. Circuit 2			2201	2202
2	Conversion of Harmon to San Vitores 34.5 kV Overhead Line to Undergr		2009	2108	2202
	a. Harmon to Tumon Sands (u/g section)				
	b. Harmon to Tumon Sands (o/h section)				
	c. Tumon Sands to San Vitores				
3	Conversion of Macheche to GAA 34.5 kV Overhead Line to Underground		2009	2211	2216
4	Marbo to Pagat 34.5 kV Line		2010		2212
5	Macheche to Harmon		2009	2202	2211
6	Wind Farm to Talofofo Sub		2011	2003	9004
7	Wind Farm to Apra Sub		2011	2004	9004
8	Alternative 1	SSD Facility to Piti Sub	2017	9024	1005
9	Alternative 1	SSD Facility to Cabras Switchyard	2017	9024	1001
10	Alternative 2	SSD Facility to Harmon Substation	2017		
11	Alternative 2	SSD Facility to Harmon Switchyard	2017		

	Transformers			
	Description	**Year In Service**	**Size**	**Load in 2010**
1	T-9 Agana Sub	2008	12 MVA	*Status and load turned on in 2008
2	Cold Storage	2010	20 MVA	10 MVA
3	Orote Substation	2010	10 MVA	26 MVA for total sub
4	SRF Substation	2010	20 MVA	15 MVA

Reconductor overhead 34.5 kV lines to 927 MCM with transmission lines serving DoD loads by 2014.

Appendix L: Summary of Costs for Project Alternatives[1]

[1] Source: John Bakken, P.E., Senior Project Manager, R.W. Beck

Base	2020 Case as provided (with Wind Capacitors removed)	Base Cost	Cost With 10% contingency
NorthA	2020 Base plus: new Harmon - Anderson 115kV new Harmon - Anderson 34.5kV UG Reconductor Harmon - Anderson 34.5kV 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)	$ 69,104,000	$ 76,014,400
NorthB	2020 Base plus: new Harmon - Anderson 34.5kV UG 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)	$ 28,050,000	$ 30,855,000
NorthC	2020 Base plus: new Harmon - North Finegayan 34.5kV UG 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)	$ 10,865,000	$ 11,951,500
NorthD	2020 Base plus: 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)	$ 795,000	$ 874,500
NorthE	2020 Base plus: new Harmon - Anderson 115kV 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)	$ 39,849,000	$ 44,033,900
NorthF	2020 Base plus: new Harmon - Anderson 115kV Reconductor Harmon - Anderson 34.5kV 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)	$ 41,849,000	$ 46,033,900

Label	Description	Cost	Cost with Contingency
Base	2020 Case as provided (with Wind Capacitors removed)		
SouthA	Base plus: Construct 115-kV OH line from Piti to Orote Construct 115 – 34.5kV substation with 112MVA transformer at Orote Install 2x6 MVAR capacitor banks at Orote Install 2x3 MVAR capacitor banks at Polaris Point Upgrade 34.5-kV OH line Piti – Cold Storage-Orote with 927 kcmil conductor. Construct 34.5-kV OH line from Piti to Polaris Point	$20,521,000	$22,573,100
SouthA2	Base plus: Install 2x6 MVAR capacitor banks at Orote Install 2x3 MVAR capacitor banks at Polaris Point Upgrade 34.5-kV OH line Piti – Cold Storage-Orote with 927 kcmil conductor. Construct 34.5-kV OH line from Piti to Polaris Point	$18,571,000	$20,428,100
SouthB	Base plus: Upgrade line Piti - Apra Heights from 34.5 kV to 115 kV Construct 115 - 34.5kV substation with 112MVA transformer at Apra Heights Construct new 34.5kV substation at Polaris Point Install 2x3 MVAR capacitor banks at Polaris Point Loop 34.5-kV line Piti - Orote into new 34.5kV substation at Polaris Point. Construct 115-34.5kV substation with 112MVA transformer at Orote Install 2x6 MVAR capacitor banks at Orote Upgrade 34.5kV OH line from Apra Heights to Orote for 115kV Re-build Tenjo 34.5kV line tap to 115kV and install 34.5-115kV transformer at Tenjo	$29,322,000	$32,254,200
SouthC	Base plus: Upgrade Piti - Apra Heights from 34.5 kV to 115 kV Construct 115 - 34.5kV substation with 112MVA transformer at Apra Heights Upgrade 34.5-kV Line Piti - Cold Storage with 927 kcmil conductor Construct new 115-34.5kV substation with 112MVA transformer at Polaris Point Install 2x3 MVAR capacitor banks at Polaris Point Loop 34.5-kV Line Piti - Cold Storage into Polaris Point Loop 115-kV line Piti - Apra Heights into new 115-34.5kV substation at Polaris Point. Construct 115-34.5kV substation with 112MVA transformer at Orote Install 2x6 MVAR capacitor banks at Orote Upgrade 34.5kV OH line from Piti Polaris Point to Orote for 115kV Re-connect Tenjo 34.5kV line from Piti-Apra Heights to Orote-Apra Heights 34.5-kV line.	$26,846,000	$29,530,600

Appendix M - Long Range Transmission Planning Work Breakdown Structure and Responsibility Assignment Matrix

Figure M-1, Long Range Transmission Planning: First Level Work Breakdown Structure

Appendix N - Candidate Expansion Plans

Candidate Northern Expansion Plans

Two Scenarios:

- 2017 Southern Baseload Generation Addition
- 2017 Northern Baseload Generation Addition

Label	Description
Base	2020 Case as provided (with Wind Capacitors removed)
NorthA	2020 Base plus: new Harmon - Anderson 115kV new Harmon - Anderson 34.5kV UG Reconductor Harmon - Anderson 34.5kV 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)
NorthB	2020 Base plus: new Harmon - Anderson 34.5kV UG 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)
NorthC	2020 Base plus: new Harmon - North Finegayan 34.5kV UG 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)
NorthD	2020 Base plus: 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)
NorthE	2020 Base plus: new Harmon - Anderson 115kV 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)
NorthF	2020 Base plus: new Harmon - Anderson 115kV Reconductor Harmon - Anderson 34.5kV 2x6 MVAr capacitor at Anderson 2x3 MVAr capacitor at North Ramp (modeled at Anderson)

Candidate Southern Expansion Plans

Two Scenarios:

- 2017 Southern Baseload Generation Addition
- 2017 Northern Baseload Generation Addition

Label	Description
Base	2020 Case as provided (with Wind Capacitors removed)
SouthA	Base plus: Construct 115-kV OH line from Piti to Orote Construct 115 – 34.5kV substation with 112MVA transformer at Orote Install 2x6 MVAR capacitor banks at Orote Install 2x3 MVAR capacitor banks at Polaris Point Upgrade 34.5-kV OH line Piti – Cold Storage-Orote with 927 kcmil conductor. Construct 34.5-kV OH line from Piti to Polaris Point
SouthA2	Base plus: Install 2x6 MVAR capacitor banks at Orote Install 2x3 MVAR capacitor banks at Polaris Point Upgrade 34.5-kV OH line Piti – Cold Storage-Orote with 927 kcmil conductor. Construct 34.5-kV OH line from Piti to Polaris Point
SouthB	Base plus: Upgrade line Piti - Apra Heights from 34.5 kV to 115 kV Construct 115 - 34.5kV substation with 112MVA transformer at Apra Heights Construct new 34.5kV substation at Polaris Point Install 2x3 MVAR capacitor banks at Polaris Point Loop 34.5-kV line Piti - Orote into new 34.5kV substation at Polaris Point. Construct 115-34.5kV substation with 112MVA transformer at Orote Install 2x6 MVAR capacitor banks at Orote Upgrade 34.5kV OH line from Apra Heights to Orote for 115kV Re-build Tenjo 34.5kV line tap to 115kV and install 34.5-115kV transformer at Tenjo
SouthC	Base plus: Upgrade Piti - Apra Heights from 34.5 kV to 115 kV Construct 115 - 34.5kV substation with 112MVA transformer at Apra Heights Upgrade 34.5-kV Line Piti - Cold Storage with 927 kcmil conductor Construct new 115-34.5kV substation with 112MVA transformer at Polaris Point Install 2x3 MVAR capacitor banks at Polaris Point Loop 34.5-kV Line Piti - Cold Storage into Polaris Point Loop 115-kV line Piti - Apra Heights into new 115-34.5kV substation at Polaris Point. Construct 115-34.5kV substation with 112MVA transformer at Orote Install 2x6 MVAR capacitor banks at Orote Upgrade 34.5kV OH line from Piti Polaris Point to Orote for 115kV Re-connect Tenjo 34.5kV line from Piti-Apra Heights to Orote-Apra Heights 34.5-kV line.

Appendix O – GE PSLF Fiscal Year Base Case File Library

NO	PRIORITY	FILE NAME	DESCRIPTION
1	1	gpa2014b-w20	2014 base with wind 20MW
2	1	gpa2014b-w40	2014 base with wind 40MW
3	1	gpa2015b-p1w20	2015 base Peak 1 with wind 20MW
4	1	gpa2015b-p2w20	2015 base Peak 2 with wind 20MW
5	1	gpa2015b-p1w40	2015 base Peak 1 with wind 40MW
6	1	gpa2015b-p2w40	2015 base Peak 2 with wind 40MW
7	2	gpa2017b-p1w20p	2017 base Peak 1 with wind 20MW & SSID at Piti
8	2	gpa2017b-p1w20h	2017 base Peak 1 with wind 20MW & SSID at Harmon
9	1	gpa2017b-p2w20p	2017 base Peak 2 with wind 20MW & SSID at Piti
10	1	gpa2017b-p2w20h	2017 base Peak 2 with wind 20MW & SSID at Harmon
11	2	gpa2017b-p1w40p	2017 base Peak 1 with wind 40MW & SSID at Piti
12	2	gpa2017b-p1w40h	2017 base Peak 1 with wind 40MW & SSID at Harmon
13	1	gpa2017b-p2w40p	2017 base Peak 2 with wind 40MW & SSID at Piti
14	1	gpa2017b-p2w40h	2017 base Peak 2 with wind 40MW & SSID at Harmon
15	1	gpa2020b-p1w40p	2020 base Peak 1 with wind 40MW & SSID at Piti
16	1	gpa2020b-p1w40h	2020 base Peak 1 with wind 40MW & SSID at Harmon
17	1	gpa2020b-p2w40p	2020 base Peak 2 with wind 40MW & SSID at Piti
18	1	gpa2020b-p2w40h	2020 base Peak 2 with wind 40MW & SSID at Harmon
19	1	gpa2020b-p1w80p	2020 base Peak 1 with wind 80MW & SSID at Piti
20	1	gpa2020b-p1w80h	2020 base Peak 1 with wind 80MW & SSID at Harmon
21	1	gpa2020b-p2w80p	2020 base Peak 2 with wind 80MW & SSID at Piti
22	1	gpa2020b-p2w80h	2020 base Peak 2 with wind 80MW & SSID at Harmon
23	3	gpa2016b-p1w40p	2016 base Peak 1 with wind 40MW & SSID at Piti
24	3	gpa2016b-p1w40h	2016 base Peak 1 with wind 40MW & SSID at Harmon
25	2	gpa2016b-p2w40p	2016 base Peak 2 with wind 40MW & SSID at Piti
26	2	gpa2016b-p2w40h	2016 base Peak 2 with wind 40MW & SSID at Harmon
27	3	gpa2018b-p1w40p	2018 base Peak 1 with wind 40MW & SSID at Piti
28	3	gpa2018b-p1w40h	2018 base Peak 1 with wind 40MW & SSID at Harmon
29	2	gpa2018b-p2w40p	2018 base Peak 2 with wind 40MW & SSID at Piti
30	2	gpa2018b-p2w40h	2018 base Peak 2 with wind 40MW & SSID at Harmon
31	3	gpa2018b-p1w60p	2018 base Peak 1 with wind 60MW & SSID at Piti
32	3	gpa2018b-p1w60h	2018 base Peak 1 with wind 60MW & SSID at Harmon
33	2	gpa2018b-p2w60p	2018 base Peak 2 with wind 60MW & SSID at Piti
34	2	gpa2018b-p2w60h	2018 base Peak 2 with wind 60MW & SSID at Harmon
35	3	gpa2019b-p1w40p	2019 base Peak 1 with wind 40MW & SSID at Piti
36	3	gpa2019b-p1w40h	2019 base Peak 1 with wind 40MW & SSID at Harmon
37	2	gpa2019b-p2w40p	2019 base Peak 2 with wind 40MW & SSID at Piti
38	2	gpa2019b-p2w40h	2019 base Peak 2 with wind 40MW & SSID at Harmon
39	3	gpa2019b-p1w60p	2019 base Peak 1 with wind 60MW & SSID at Piti
40	3	gpa2019b-p1w60h	2019 base Peak 1 with wind 60MW & SSID at Harmon
41	2	gpa2019b-p2w60p	2019 base Peak 2 with wind 60MW & SSID at Piti
42	2	gpa2019b-p2w60h	2019 base Peak 2 with wind 60MW & SSID at Harmon

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Appendix Q - Acknowledgements

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Appendix R - Case Study PSLF Runs Made

Priority	Year	Base Peak	Transient Peak Scenario		Wind - Apra			Wind - Talofofo			New Baseload		Contingencies		Dispatch Scenario				
			1	2									Single	Double	Normal Dispatch	One Cab Steam Unit Out	One Cab SSD Unit Out	One MEC Unit Out	One Tango Unit Out
1	2014	X			20	40		20	40				X	X	X	X	X	X	X
	2015		X	X	20	40		20	40				X	X	X	X	X	X	X
	2017		X	X	20	40		20	40		Piti	Harmon	X	X	X	X	X	X	X
	2020		X	X		40	80		40	80	Piti	Harmon	X	X	X	X	X	X	X
2	2016		X	X		40			40		Piti	Harmon	X	X	X	X	X	X	X
	2018		X	X		40	60		40	60	Piti	Harmon	X	X	X	X	X	X	X
	2019		X	X		40	60		40	60	Piti	Harmon	X	X	X	X	X	X	X

20 MW at Apra + 20 MW at Tal
40 MW at Apra + 40 MW at Tal
60 MW at Apra + 60 MW at Tal
80 MW at Apra + 80 MW at Tal

Preliminary Analysis Results: FY 2020 Transformer Overloads – No Improvements to System – No Contingencies

CASE DESCRIPTION	FROM	FNAME	FKV	TO	TNAME	TKV	CK	ST	P	Q	MVA	AMPS	%RATE	RATE	UNIT
2020b-p1w40h.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	8	26.4	456.1	117.8	22.4	Mva
2020b-p1w40h.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.2	27.5	484.6	122.8	22.4	Mva
2020b-p1w40h.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.7	22.7	417.8	101.5	22.4	Mva
2020b-p1w40h.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.8	22.7	33.6	656.3	420.3	8.0	Mva
2020b-p1w40p.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	8	26.4	460.4	117.9	22.4	Mva
2020b-p1w40p.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.4	27.6	491.7	123.1	22.4	Mva
2020b-p1w40p.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.8	22.8	423.8	101.6	22.4	Mva
2020b-p1w40p.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.9	23.7	34.4	683.1	429.8	8.0	Mva
2020b-p1w40p.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	-29.8	-22.6	37.4	742.8	123.3	602.5	Amp
2020b-p1w80h.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	7.9	26.4	453.4	117.7	22.4	Mva
2020b-p1w80h.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.2	27.5	480.2	122.6	22.4	Mva
2020b-p1w80h.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.6	22.7	406.9	101.3	22.4	Mva
2020b-p1w80h.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.8	21.9	33.1	636.2	413.5	8.0	Mva
2020b-p1w80h.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	-28.3	-21.2	35.4	680.2	112.9	602.5	Amp
2020b-p1w80p.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	7.9	26.4	454.9	117.7	22.4	Mva
2020b-p1w80p.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.2	27.5	482.7	122.7	22.4	Mva
2020b-p1w80p.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.6	22.7	408.8	101.3	22.4	Mva
2020b-p1w80p.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.8	22.2	33.3	644.5	416.3	8.0	Mva
2020b-p2w40h.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	7.9	26.4	455.3	117.8	22.4	Mva
2020b-p2w40h.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.2	27.5	483.8	122.8	22.4	Mva
2020b-p2w40h.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.7	22.7	417.1	101.5	22.4	Mva
2020b-p2w40h.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.8	22.6	33.6	653.7	419.4	8.0	Mva
2020b-p2w40p.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	8	26.4	457.8	117.8	22.4	Mva
2020b-p2w40p.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.3	27.5	487.7	123.0	22.4	Mva
2020b-p2w40p.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.8	22.7	420.4	101.5	22.4	Mva
2020b-p2w40p.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.9	23.1	34.0	668.1	424.4	8.0	Mva
2020b-p2w80h.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	7.9	26.4	455.7	117.8	22.4	Mva
2020b-p2w80h.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.2	27.5	484.3	122.8	22.4	Mva
2020b-p2w80h.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.7	22.7	417.6	101.5	22.4	Mva
2020b-p2w80h.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.8	22.7	33.6	656.6	420.4	8.0	Mva
2020b-p2w80p.sav	2101	Aga345	34.5	3102	AganaT65	13.8	2	1	25.2	7.9	26.4	453.9	117.7	22.4	Mva
2020b-p2w80p.sav	2105	Tum345B1	34.5	3107	TumonT60	13.8	2	1	22.9	15.2	27.5	482.0	122.7	22.4	Mva
2020b-p2w80p.sav	2203	Ded345B1	34.5	3204	DededT55	13.8	1	1	21.7	6.6	22.7	408.4	101.3	22.4	Mva
2020b-p2w80p.sav	2208	NCS345	34.5	4201	NCS T47	4.2	1	1	24.8	22.3	33.3	645.8	416.7	8.0	Mva

Preliminary Analysis Results: FY 2020 Transformer Overloads – No Improvements to System – No Contingencies

CASE DESCRIPTION	FROM	FNAME	FKV	TO	TNAME	TKV	CK	ST	P	Q	MVA	AMPS	%RATE	RATE	UNIT
2020b-p1w40h.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(29.8)	(22.1)	37.1	724.7	120.3	602.5	Amp
2020b-p1w40p.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(29.8)	(22.6)	37.4	742.8	123.3	602.5	Amp
2020b-p1w80h.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(28.3)	(21.2)	35.4	680.2	112.9	602.5	Amp
2020b-p1w80p.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(28.2)	(21.3)	35.4	684.2	113.6	602.5	Amp
2020b-p2w40h.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(29.8)	(22.1)	37.1	722.6	119.9	602.5	Amp
2020b-p2w40p.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(29.7)	(22.3)	37.2	731.8	121.5	602.5	Amp
2020b-p2w80h.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(29.7)	(22.2)	37.1	724.0	120.2	602.5	Amp
2020b-p2w80p.sav	2208	NCS345	34.5	2219	Har345B1	34.5	1	1	(28.7)	(21.5)	35.9	694.7	115.3	602.5	Amp

Appendix T – Load Forecast Notes

Load Forecast

This load forecast is based on the Energy Sales (kWh) forecast allocated by rate class provided by PL Mangilao / Kemm Farney. Since the power flow analysis software (GE pslf) requires the load data to be allocated by substation transformer, the PL Mangilao / Kemm Farney forecast is converted using historical customer energy consumption data from the Utiligy database. The conversion process requires a statistical relationship between the two types of data which was found in GPA's 1994 Load Research Study.

1. The file 'annual kWh summary rev.xls' allocates the 2007 base case load in the pslf model by rate class and substation transformer. The load in the existing model is currently only allocated by substation transformer. The rate class allocation is accomplished by using the Utiligy database which has customer energy (kWh) consumption allocated by both rate class and distribution feeder. The distribution feeders are then assigned to the corresponding substation transformer.
    a. The Crystal Report 'history rev.rpt' summarizes the annual customer energy (kWh) consumption from 9/1/08 to 8/31/08 by rate class and distribution feeder. Note: When the old CIS JDE system (pre-Utiligy) was used, feeder info was entered with each new account. However, this was discontinued when we switched to the new Utiligy system in 2005.
    b. The Crystal Report summary is pasted onto a table on sheet 'crystal-utiligy'. The respective substation transformer is assigned to each feeder using a lookup table on sheet 'lookup'. The rate classes G, J, K and S are divided into two categories (e.g. SCHG1 and SCHG3) corresponding to single-phase and three-phase customers.
        i. The second table on the sheet consolidates the single-phase and three-phase rate classes into one rate class (e.g. SCHG1 and SCHG3 become SCHG).
        ii. The pivot table at the bottom sums the total customer consumption by rate class and substation transformer.
    c. The pivot table results are pasted onto sheet 'crys-util by xfmr'.
        i. The second table compares the substation transformer lists between Utiligy and the pslf model. The substation transformers that are found in the pslf model but not the Utiligy database are: GIAT, generator station power (STA), T-115 (Pagat), T-122 (San Vitores), and Navy's. In the 2007 pslf model, the status of Navy's T-9 and T-14 are off because they are pending repairs. Their loads are currently being served by GPA feeders P-282 and P-89. These transformers should be turned on for the year of the scheduled repair. Harmon's T-44 is also off. Verify the schedule with Joven or Irwin. Victor Dock's T-43, T-44, and T-45 are off because their loads were consolidated into T-42 which corresponds to Navy's X-34 load.
        ii. The third table lists all the substation transformers found in the pslf model and indicates the percentage of the load for each rate class. For most, the rate class allocation is based on the Utiligy data from the first table. Station Power (STA) and GIAT rate classes were obtained from Accounting (Jorna). T-115 and T-122 are estimated because no data was found in Utiligy. Rate classes

for Navy transformers are based on sheet 'navy hist'. T-14, T-44 and T-9 are off in the 2007 pslf model.

iii. The fourth table allocates the 2007 peak load (MW) in the pslf model by rate class and substation transformer. The Private Outdoor Lighting (H) and Street Lighting (F) rate classes are added to the list. For each transformer, the rate class percentages from the third table are multiplied by the pslf peak load for the respective transformer. The peak load is found on sheet 'load from pslf'. Rate classes H and F are estimated by dividing their forecasted 2007 MW demand loads by 19, which is the total number of transformers excluding GIAT, STA, and Navy. The results from this table are used in the file 'load forecast by xfmr 080925.xls'.

d. The sheet 'navy hist' estimates the percentage of civilian load on the Navy transformers. The calculation is based on a twelve month average obtained from the Navy billing spreadsheets from Jorna or Joven. The civilian loads are further subdivided into rate class percentages based on the CSA metering reports (pdf) from Jorna.
e. The sheet 'load from pslf' is exported from the 2007 pslf model. The pivot table at the bottom sums the total MW load for each transformer.
f. The sheet 'lookup' contains the lookup table used to determine which substation transformer each feeder belongs to. Another table indicates the respective bus number used in the pslf model.
g. The sheet 'comparison' compares the total consumption from Utiligy and the Navy billing to the FY07 actuals from Accounting. Note that the Utiligy data time period is closer to FY08.
h. The sheet 'gov accounts' has the FY07 GovGuam power consumption.
i. The sheet 'navy' has the FY07 Navy consumption.
j. The sheet 'may2007' is a sample Navy billing spreadsheet.

2. The file 'load forecast by xfmr 080925.xls'

Appendix U - EDP Handbook and Tutorial

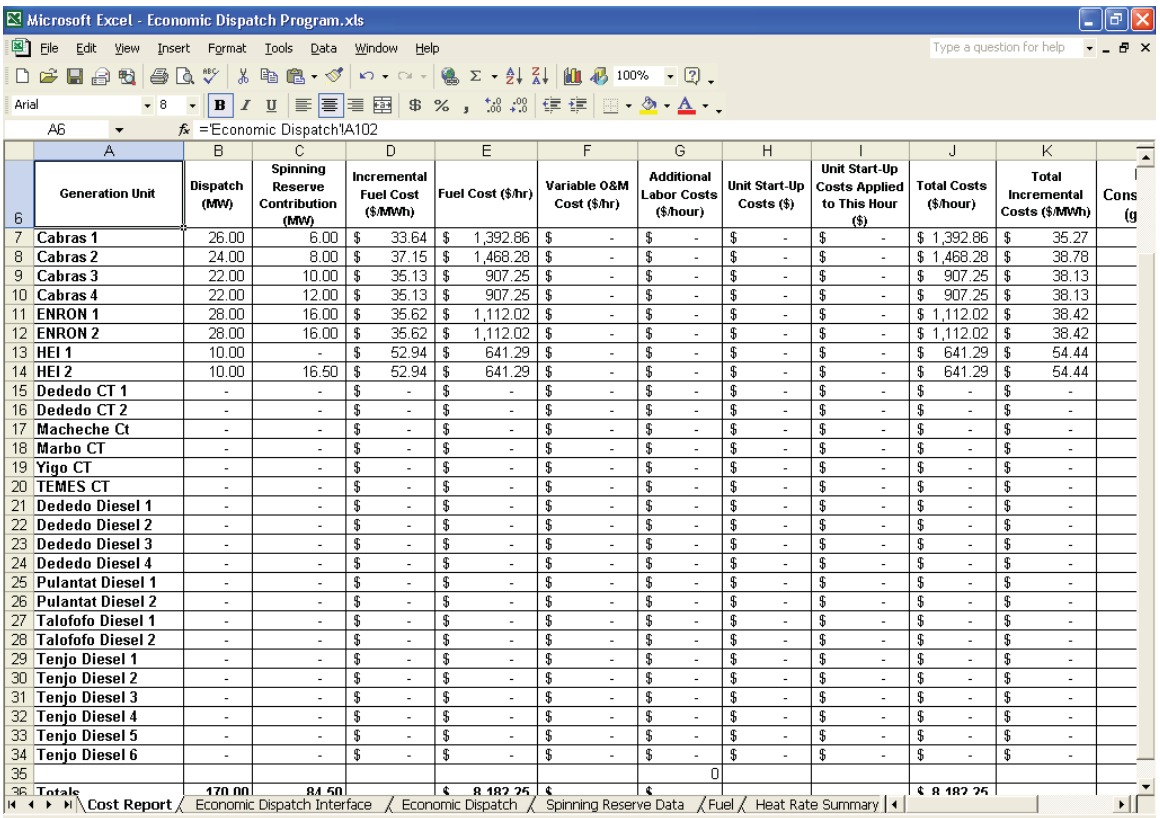
TABLE OF CONTENTS

Explanation of Worksheets

LEGEND
Calculated Data Column/Row
User Input Data Column/Row

1. Cost Report Sheet

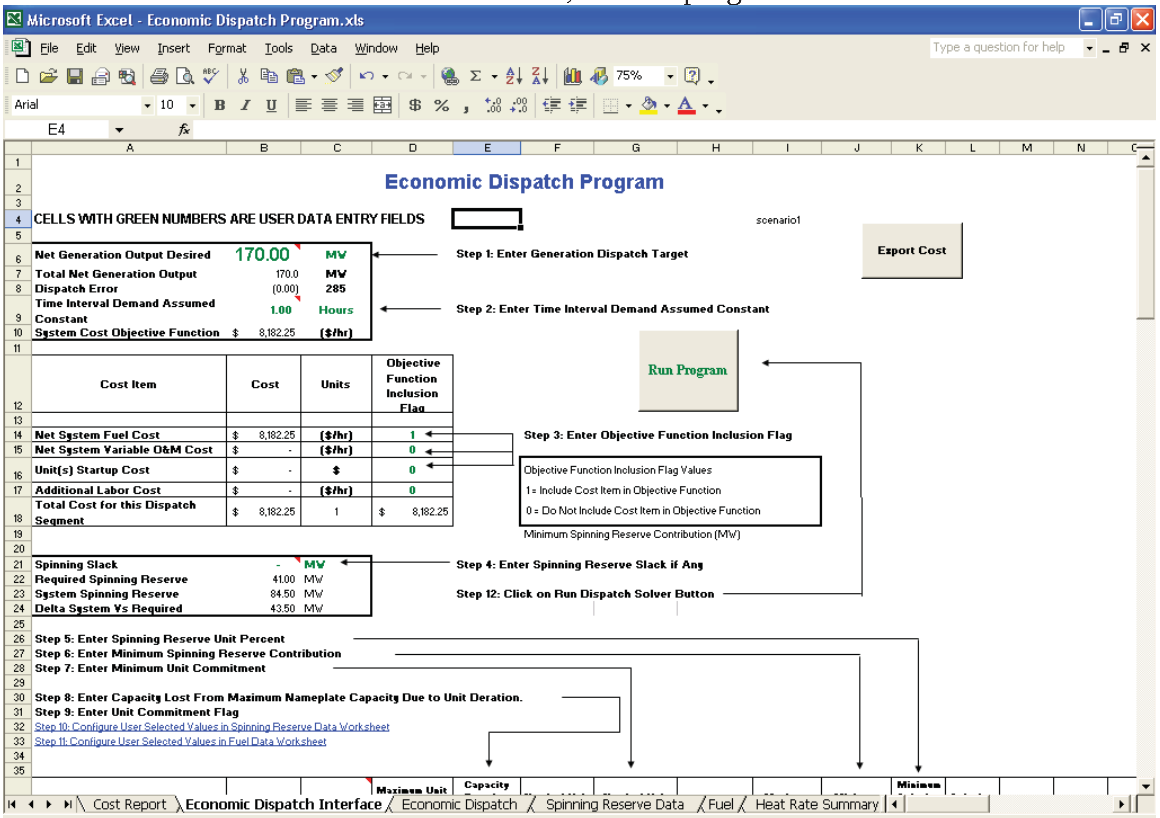
This sheet displays the results of the Economic Dispatch Program after the results have been calculated. The sheet provides a breakdown of the cost to operate under the specified conditions by each generation unit.



	A	B	C	D	E	F	G	H	I	J	K	L
6	Generation Unit	Dispatch (MW)	Spinning Reserve Contribution (MW)	Incremental Fuel Cost ($/MWh)	Fuel Cost ($/hr)	Variable O&M Cost ($/hr)	Additional Labor Costs ($/hour)	Unit Start-Up Costs ($)	Unit Start-Up Costs Applied to This Hour ($)	Total Costs ($/hour)	Total Incremental Costs ($/MWh)	Cons (g
7	Cabras 1	26.00	6.00	$ 33.64	$ 1,392.86	$ -	$ -	$ -	$ -	$ 1,392.86	$ 35.27	
8	Cabras 2	24.00	8.00	$ 37.15	$ 1,468.28	$ -	$ -	$ -	$ -	$ 1,468.28	$ 38.78	
9	Cabras 3	22.00	10.00	$ 35.13	$ 907.25	$ -	$ -	$ -	$ -	$ 907.25	$ 38.13	
10	Cabras 4	22.00	12.00	$ 35.13	$ 907.25	$ -	$ -	$ -	$ -	$ 907.25	$ 38.13	
11	ENRON 1	28.00	16.00	$ 35.62	$ 1,112.02	$ -	$ -	$ -	$ -	$ 1,112.02	$ 38.42	
12	ENRON 2	28.00	16.00	$ 35.62	$ 1,112.02	$ -	$ -	$ -	$ -	$ 1,112.02	$ 38.42	
13	HEI 1	10.00	-	$ 52.94	$ 641.29	$ -	$ -	$ -	$ -	$ 641.29	$ 54.44	
14	HEI 2	10.00	16.50	$ 52.94	$ 641.29	$ -	$ -	$ -	$ -	$ 641.29	$ 54.44	
15	Dededo CT 1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
16	Dededo CT 2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
17	Macheche Ct	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
18	Marbo CT	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19	Yigo CT	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	TEMES CT	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	Dededo Diesel 1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
22	Dededo Diesel 2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
23	Dededo Diesel 3	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
24	Dededo Diesel 4	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
25	Pulantat Diesel 1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
26	Pulantat Diesel 2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
27	Talofofo Diesel 1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
28	Talofofo Diesel 2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
29	Tenjo Diesel 1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
30	Tenjo Diesel 2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
31	Tenjo Diesel 3	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
32	Tenjo Diesel 4	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
33	Tenjo Diesel 5	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34	Tenjo Diesel 6	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
35							0					
36	Totals	170.00	84.50		$ 8,182.25	$	$			$ 8,182.25		

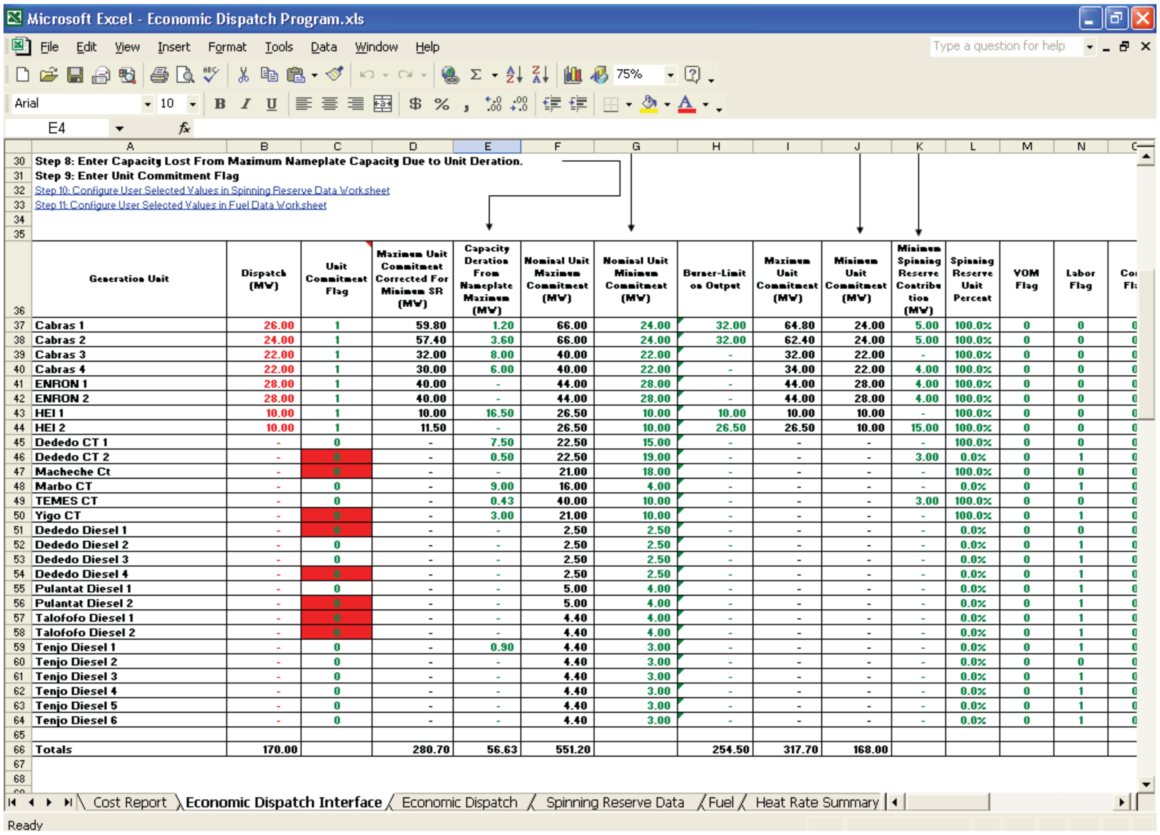
2. Economic Dispatch Interface (EDI) Sheet

In this sheet the bulk of the variables are set, and the program is initiated.



<u>Net Generation Output Desired</u> – The amount of energy in megawatts to be provided by the system, i.e. the load.
<u>Total Net Generation Output</u> - The net amount of power provided by the system using current calculations.
<u>Dispatch Error</u> – The amount by which the net generation output varies from the desired output.
<u>Time Interval Demand Assumed Constant</u> – The length of time to maintain the desired output level.
<u>System Cost Objective Function</u> – The total cost to run the system at calculated values for the time specified.

<u>Objective Function Inclusion Flag</u> – Whether or not to calculate the specified cost in calculation of the total cost.
0 – Do not include cost 1 – Include cost



Generation Unit	Dispatch (MW)	Unit Commitment Flag	Maximum Unit Commitment Corrected For Minimum SR (MW)	Capacity Deration From Nameplate Maximum (MW)	Nominal Unit Maximum Commitment (MW)	Nominal Unit Minimum Commitment (MW)	Burner-Limit on Output	Maximum Unit Commitment (MW)	Minimum Unit Commitment (MW)	Minimum Spinning Reserve Contribution (MW)	Spinning Reserve Unit Percent	VOM Flag	Labor Flag	Co Fl
Cabras 1	26.00	1	59.80	1.20	66.00	24.00	32.00	64.80	24.00	5.00	100.0%	0	0	0
Cabras 2	24.00	1	57.40	3.60	66.00	24.00	32.00	62.40	24.00	5.00	100.0%	0	0	0
Cabras 3	22.00	1	32.00	8.00	40.00	22.00	-	32.00	22.00	-	100.0%	0	0	0
Cabras 4	22.00	1	30.00	6.00	40.00	22.00	-	34.00	22.00	4.00	100.0%	0	0	0
ENRON 1	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
ENRON 2	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
HEI 1	10.00	1	10.00	16.50	26.50	10.00	10.00	10.00	10.00	-	100.0%	0	0	0
HEI 2	10.00	1	11.50	-	26.50	10.00	26.50	26.50	10.00	15.00	100.0%	0	0	0
Dededo CT 1	-	0	-	7.50	22.50	15.00	-	-	-	-	100.0%	0	0	0
Dededo CT 2	-	0	-	0.50	22.50	19.00	-	-	-	3.00	0.0%	0	1	0
Macheche Ct	-	0	-	-	21.00	18.00	-	-	-	-	100.0%	0	0	0
Marbo CT	-	0	-	9.00	16.00	4.00	-	-	-	-	0.0%	0	1	0
TEMES CT	-	0	-	0.43	40.00	10.00	-	-	-	3.00	100.0%	0	0	0
Yigo CT	-	0	-	3.00	21.00	10.00	-	-	-	-	100.0%	0	1	0
Dededo Diesel 1	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	0	0
Dededo Diesel 2	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 3	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 4	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 1	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 2	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 1	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 2	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 1	-	0	-	0.90	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 2	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	0	0
Tenjo Diesel 3	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 4	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 5	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 6	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Totals	170.00		280.70	56.63	551.20		254.50	317.70	168.00					

Dispatch – Amount of power distributed by generation unit, calculated by program
Unit Commitment Flag – Determines how unit is to be used.
-1 – Make Minimum Unit Commitment equal to zero. Make Maximum Unit Commitment equal to Nominal Maximum Unit Commitment minus Capacity Deration From Nameplate. Allows the unit to be dispatched based on economics without regard to physical minimum sustained output limitations. Use to find the next unit to bring on-line.
0 – Make Maximum and Minimum Unit Commitment equal to zero MW.
1 – Make Minimum Unit Commitment equal to Nominal Minimum Unit Commitment. Make Maximum Unit Commitment equal to Nominal Maximum Unit Commitment minus Capacity Deration From Nameplate. Allows the unit to be dispatched based on economics subject to physical minimum sustained output limitations.
2 – Make Minimum Unit Commitment equal to Nominal Minimum Unit Commitment. Make Maximum Unit Commitment equal to Nominal Maximum Unit Commitment minus Capacity Deration From Nameplate. Allows the unit to be dispatched based on economics subject to physical minimum sustained output limitations. Includes Unit Start-up Cost.
3 – Make Maximum and Minimum Unit Commitment equal to zero MW. Include Costs for Hot Standby Condition.
Maximum Unit Commitment Corrected For Minimum SR (MW) – The maximum power a unit can provide, taking into account spinning reserve and capacity deration
Capacity Deration From Nameplate Maximum (MW) – Amount by which unit is below rated capacity

Nominal Unit Maximum Commitment (MW) – The maximum that the generation unit can be run at factoring in capacity deration

Nominal Unit Minimum Commitment (MW) – The physical minimum that the generation unit can be run at.

Burner-Limit on Output – for Cab01-02 and Tan01-02. Determines the maximum output based on the number of burners being used in each unit.

Maximum Unit Commitment (MW) – The maximum that this unit can be committed to including capacity deration, only displayed if unit commitment flag is set.

Minimum Unit Commitment (MW) – The minimum that this unit can be committed to, only displayed if unit commitment flag is set.

Minimum Spinning Reserve Contribution (MW) – The minimum amount of spinning reserve this unit should provide the system.

Spinning Reserve Unit Percent – Percent of excess generation unit will provide spinning reserve.

VOM Flag – Marks whether the Variable O&M costs should be added.

0 – Do not include costs 1 – Include costs

Labor Flag – Marks whether addition overtime labor should be added.

0 – Do not include costs 1 – Include costs

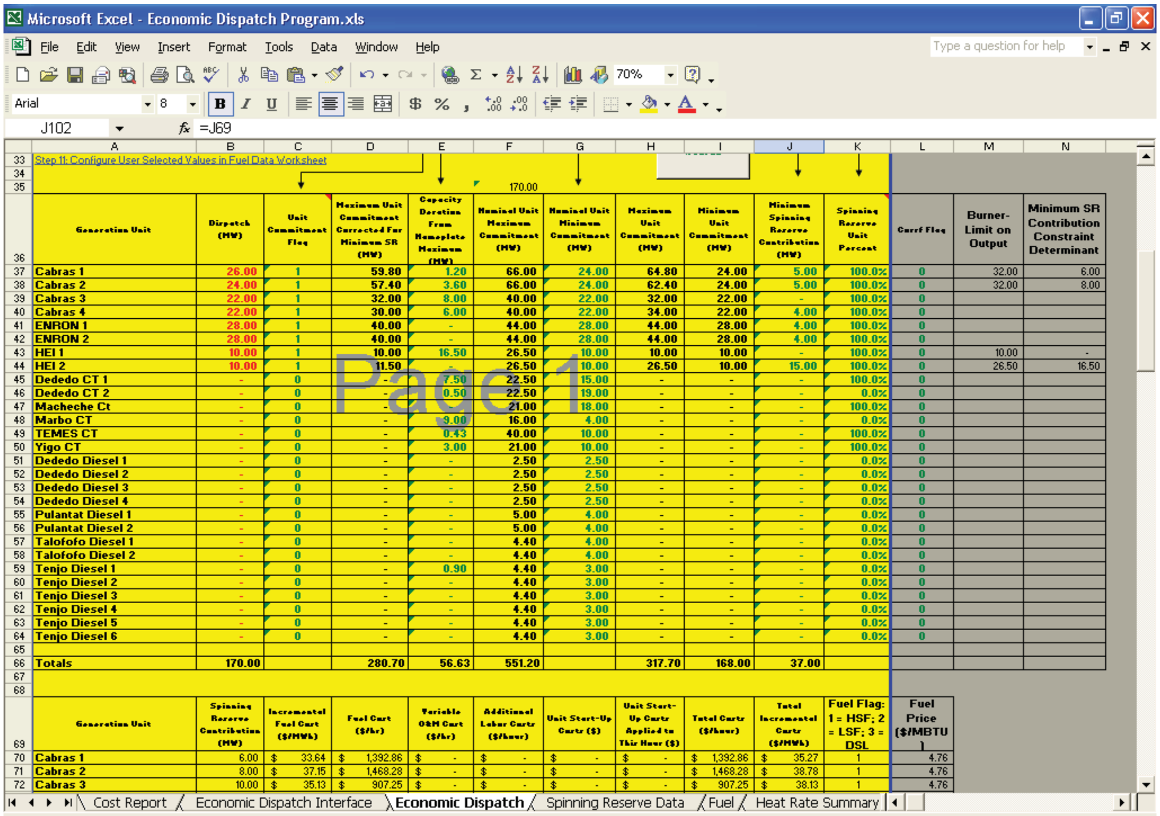
Corrf Flag – Based on EDI, marks if corrf should be applied to fuel costs for unit.

0 – Do not include costs 1 – Include costs

Burner-Limit on Output – for Cab01-02 and Tan01-02. Determines the maximum output based on the number of burners being used in each unit.

3. Economic Dispatch Sheet

This sheet is primarily used by the program for calculations. Most cells are either formulas or are referenced data.

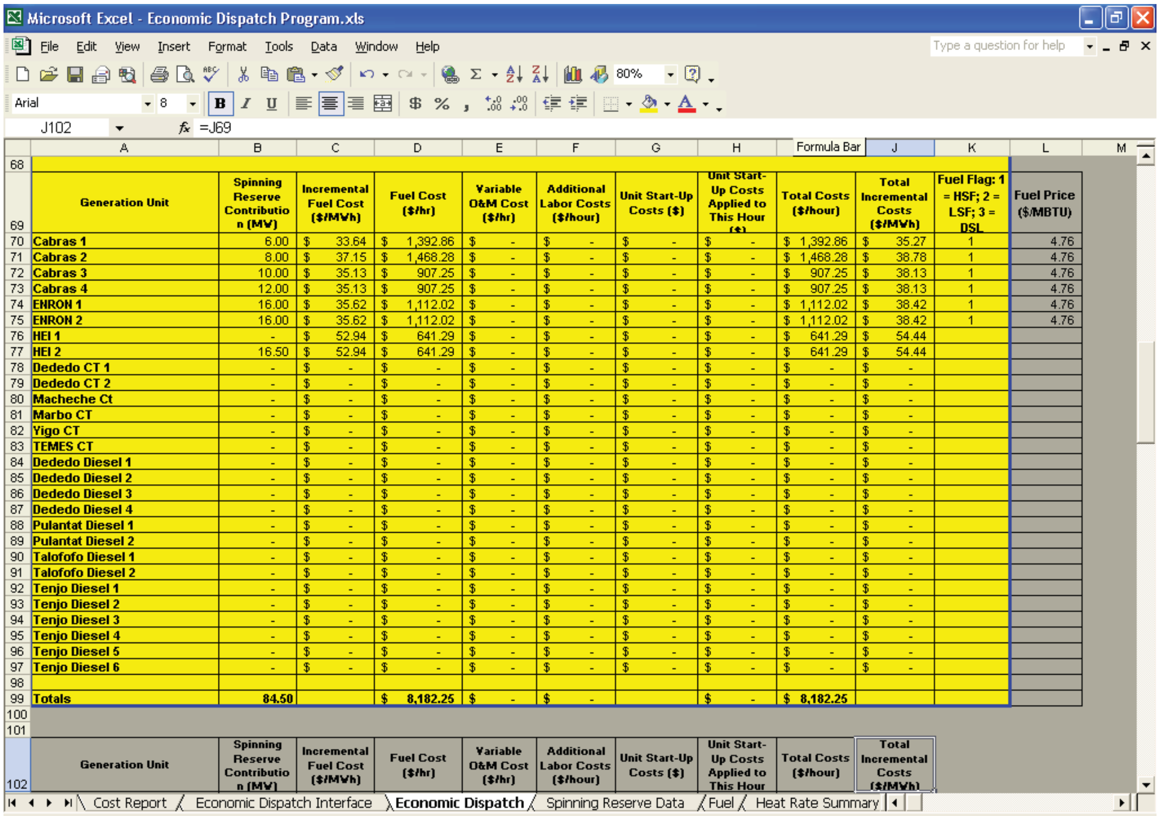


Row	Generation Unit	Dispatch (MW)	Unit Commitment Flag	Maximum Unit Commitment Corrected For Minimum SR (MW)	Capacity Deration From Nameplate Maximum (MW)	Nominal Unit Maximum Commitment (MW)	Nominal Unit Minimum Commitment (MW)	Maximum Unit Commitment (MW)	Minimum Unit Commitment (MW)	Minimum Spinning Reserve Contribution (MW)	Spinning Reserve Unit Percent	Conf Flag	Burner-Limit on Output	Minimum SR Contribution Constraint Determinant
37	Cabras 1	26.00	1	59.80	1.20	66.00	24.00	64.80	24.00	5.00	100.0%	0	32.00	6.00
38	Cabras 2	24.00	1	57.40	3.60	66.00	24.00	62.40	24.00	5.00	100.0%	0	32.00	8.00
39	Cabras 3	22.00	1	32.00	8.00	40.00	22.00	32.00	22.00	-	100.0%	0		
40	Cabras 4	22.00	1	30.00	6.00	40.00	22.00	34.00	22.00	4.00	100.0%	0		
41	ENRON 1	28.00	1	40.00	-	44.00	28.00	44.00	28.00	4.00	100.0%	0		
42	ENRON 2	28.00	1	40.00	-	44.00	28.00	44.00	28.00	4.00	100.0%	0		
43	HEI 1	10.00	1	10.00	16.50	26.50	10.00	10.00	10.00	-	100.0%	0	10.00	-
44	HEI 2	10.00	1	11.50	-	26.50	10.00	26.50	10.00	15.00	100.0%	0	26.50	16.50
45	Dededo CT 1	-	0	-	7.50	22.50	15.00	-	-	-	100.0%	0		
46	Dededo CT 2	-	0	-	0.50	22.50	19.00	-	-	-	0.0%	0		
47	Macheche Ct	-	0	-	-	21.00	18.00	-	-	-	100.0%	0		
48	Marbo CT	-	0	-	9.00	16.00	4.00	-	-	-	0.0%	0		
49	TEMES CT	-	0	-	0.43	40.00	10.00	-	-	-	100.0%	0		
50	Yigo CT	-	0	-	3.00	21.00	10.00	-	-	-	100.0%	0		
51	Dededo Diesel 1	-	0	-	-	2.50	2.50	-	-	-	0.0%	0		
52	Dededo Diesel 2	-	0	-	-	2.50	2.50	-	-	-	0.0%	0		
53	Dededo Diesel 3	-	0	-	-	2.50	2.50	-	-	-	0.0%	0		
54	Dededo Diesel 4	-	0	-	-	2.50	2.50	-	-	-	0.0%	0		
55	Pulantat Diesel 1	-	0	-	-	5.00	4.00	-	-	-	0.0%	0		
56	Pulantat Diesel 2	-	0	-	-	5.00	4.00	-	-	-	0.0%	0		
57	Talofofo Diesel 1	-	0	-	-	4.40	4.00	-	-	-	0.0%	0		
58	Talofofo Diesel 2	-	0	-	-	4.40	4.00	-	-	-	0.0%	0		
59	Tenjo Diesel 1	-	0	-	0.90	4.40	3.00	-	-	-	0.0%	0		
60	Tenjo Diesel 2	-	0	-	-	4.40	3.00	-	-	-	0.0%	0		
61	Tenjo Diesel 3	-	0	-	-	4.40	3.00	-	-	-	0.0%	0		
62	Tenjo Diesel 4	-	0	-	-	4.40	3.00	-	-	-	0.0%	0		
63	Tenjo Diesel 5	-	0	-	-	4.40	3.00	-	-	-	0.0%	0		
64	Tenjo Diesel 6	-	0	-	-	4.40	3.00	-	-	-	0.0%	0		
65														
66	Totals	170.00		280.70	56.63	551.20		317.70	168.00	37.00				

Row	Generation Unit	Spinning Reserve Contribution (MW)	Incremental Fuel Cost ($/MWh)	Fuel Cost ($/hr)	Variable O&M Cost ($/hr)	Additional Labor Costs ($/hour)	Unit Start-Up Costs ($)	Unit Start-Up Costs Applied to This Hour ($)	Total Costs ($/hour)	Total Incremental Costs ($/MWh)	Fuel Flag: 1 = HSF; 2 = LSF; 3 = DSL	Fuel Price ($/MBTU)
70	Cabras 1	6.00	$ 33.64	$ 1,392.86	$ -	$ -	$ -	$ -	$ 1,392.86	$ 35.27	1	4.76
71	Cabras 2	8.00	$ 37.15	$ 1,468.28	$ -	$ -	$ -	$ -	$ 1,468.28	$ 38.78	1	4.76
72	Cabras 3	10.00	$ 35.13	$ 907.25	$ -	$ -	$ -	$ -	$ 907.25	$ 38.13	1	4.76

Dispatch – Amount of power distributed by generation unit, calculated by program
Unit Commitment Flag – Determines how unit is to be used, taken from EDI sheet
Maximum Unit Commitment Corrected For Minimum SR (MW) – The maximum power a unit can provide, taking into account spinning reserve and capacity deration
Capacity Deration From Nameplate Maximum (MW) – Amount by which unit is below rated capacity, taken from EDI sheet
Nominal Unit Maximum Commitment (MW) – The maximum that the generation unit can be run at factoring in capacity deration
Nominal Unit Minimum Commitment (MW) – The physical minimum that the generation unit can be run at.
Maximum Unit Commitment (MW) – The maximum that this unit can be committed to including capacity deration, only displayed if unit commitment flag is set.
Minimum Unit Commitment (MW) – The minimum that this unit can be committed to, only displayed if unit commitment flag is set.
Minimum Spinning Reserve Contribution (MW) – The minimum amount of spinning reserve this unit should provide the system. Based on EDI value, furthermore, the amount of spinning reserve is double the EDI value if Commitment flag is set to 2.
Spinning Reserve Unit Percent – Percent of excess generation unit will provide spinning reserve.

Corrf Flag – Based on EDI, marks if corrf should be applied to fuel costs for unit.
Burner-Limit on Output – for Cab01-02 and Tan01-02. Determines the maximum output based on the number of burners being used in each unit.
Minimum SR Contribution Constraint Determinant – for Cab01-02 and Tan01-02. Determines the available spinning reserve based on burner-limits on output.

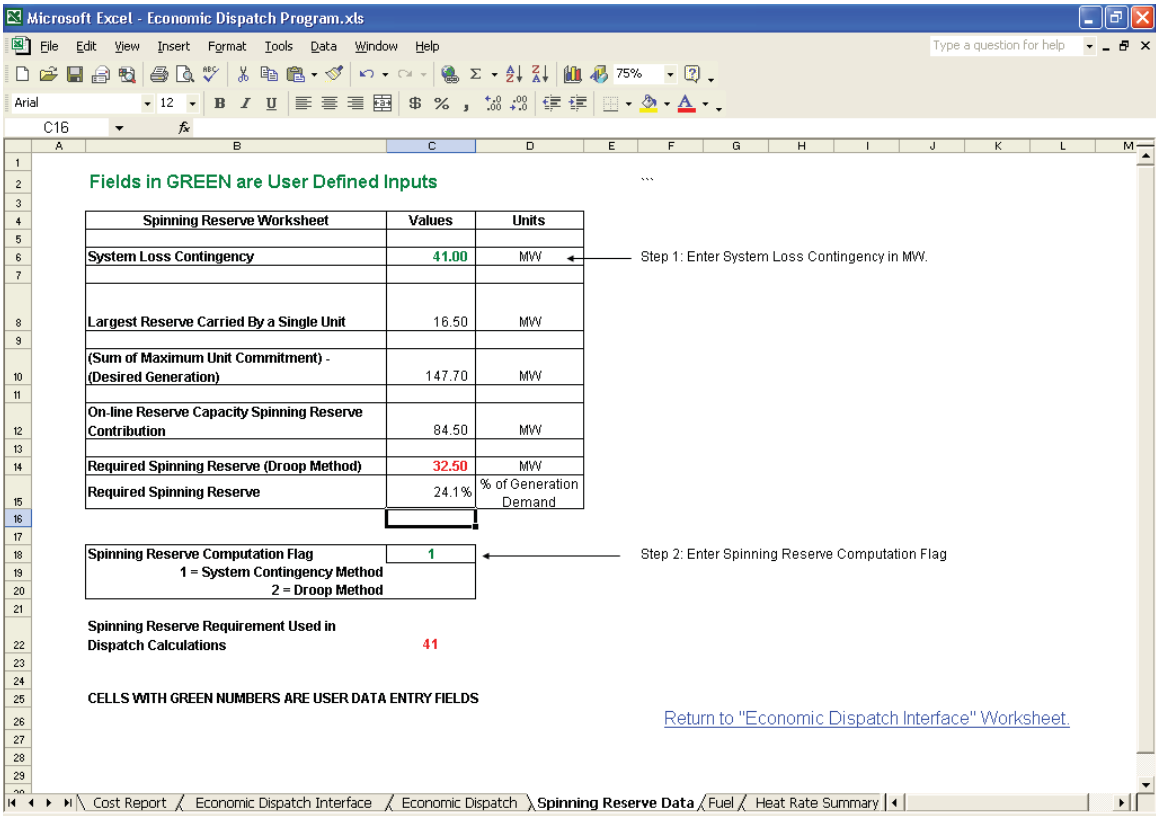


Generation Unit	Spinning Reserve Contribution (MW)	Incremental Fuel Cost ($/MWh)	Fuel Cost ($/hr)	Variable O&M Cost ($/hr)	Additional Labor Costs ($/hour)	Unit Start-Up Costs ($)	Unit Start-Up Costs Applied to This Hour ($)	Total Costs ($/hour)	Total Incremental Costs ($/MWh)	Fuel Flag: 1 = HSF; 2 = LSF; 3 = DSL	Fuel Price ($/MBTU)
Cabras 1	6.00	$ 33.64	$ 1,392.86	$ -	$ -	$ -	$ -	$ 1,392.86	$ 35.27	1	4.76
Cabras 2	8.00	$ 37.15	$ 1,468.28	$ -	$ -	$ -	$ -	$ 1,468.28	$ 38.78	1	4.76
Cabras 3	10.00	$ 35.13	$ 907.25	$ -	$ -	$ -	$ -	$ 907.25	$ 38.13	1	4.76
Cabras 4	12.00	$ 35.13	$ 907.25	$ -	$ -	$ -	$ -	$ 907.25	$ 38.13	1	4.76
ENRON 1	16.00	$ 35.62	$ 1,112.02	$ -	$ -	$ -	$ -	$ 1,112.02	$ 38.42	1	4.76
ENRON 2	16.00	$ 35.62	$ 1,112.02	$ -	$ -	$ -	$ -	$ 1,112.02	$ 38.42	1	4.76
HEI 1	-	$ 52.94	$ 641.29	$ -	$ -	$ -	$ -	$ 641.29	$ 54.44		
HEI 2	16.50	$ 52.94	$ 641.29	$ -	$ -	$ -	$ -	$ 641.29	$ 54.44		
Dededo CT 1	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Dededo CT 2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Macheche Ct	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Marbo CT	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Yigo CT	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
TEMES CT	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Dededo Diesel 1	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Dededo Diesel 2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Dededo Diesel 3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Dededo Diesel 4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Pulantat Diesel 1	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Pulantat Diesel 2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Talofofo Diesel 1	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Talofofo Diesel 2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Tenjo Diesel 1	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Tenjo Diesel 2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Tenjo Diesel 3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Tenjo Diesel 4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Tenjo Diesel 5	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Tenjo Diesel 6	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Totals	84.50		$ 8,182.25	$ -	$ -		$ -	$ 8,182.25			

Generation Unit	Spinning Reserve Contribution (MW)	Incremental Fuel Cost ($/MWh)	Fuel Cost ($/hr)	Variable O&M Cost ($/hr)	Additional Labor Costs ($/hour)	Unit Start-Up Costs ($)	Unit Start-Up Costs Applied to This Hour	Total Costs ($/hour)	Total Incremental Costs ($/MWh)

Spinning Reserve Contribution (MW) – The amount of spinning reserve a unit can provide, either the stated minimum contribution or the unused capacity of a unit.
Incremental Fuel Cost ($/MWh) – The cost to produce an additional MWh of power.
Fuel Cost ($/hr) – The cost of fuel per hour.
Variable O&M Cost ($/hr) – The cost of O&M is calculated and displayed if VOM flag from EDI is turned on.
Additional Labor Costs ($/hour) – The cost of additional labor is calculated and displayed if Labor flag from EDI is turned on.
Unit Start-Up Costs ($) – Any costs associated with starting up the unit.
Unit Start-Up Costs Applied to This Hour ($) – Indicates if any start-up costs applied to this hour, costs are calculated when the unit Commitment Flag is set to 2.
Total Costs ($/hour) – Sum of all costs involved in operating the unit.
Total Incremental Costs ($/MWh) – Sum of incremental costs for the unit.
Fuel Flag: 1 = HSF; 2 = LSF; 3 = DSL – Indicates type of fuel used in unit.
1 – High Sulfur Fuel 2 – Low Sulfur Fuel 3 – Diesel Fuel
Fuel Price ($/MBTU) – The price of the fuel, based on fuel flag and fuel prices.

4. Spinning Reserve Data Sheet



Spinning Reserve Worksheet	Values	Units
System Loss Contingency	41.00	MW
Largest Reserve Carried By a Single Unit	16.50	MW
(Sum of Maximum Unit Commitment) - (Desired Generation)	147.70	MW
On-line Reserve Capacity Spinning Reserve Contribution	84.50	MW
Required Spinning Reserve (Droop Method)	32.50	MW
Required Spinning Reserve	24.1%	% of Generation Demand

Spinning Reserve Computation Flag 1 = System Contingency Method 2 = Droop Method	1

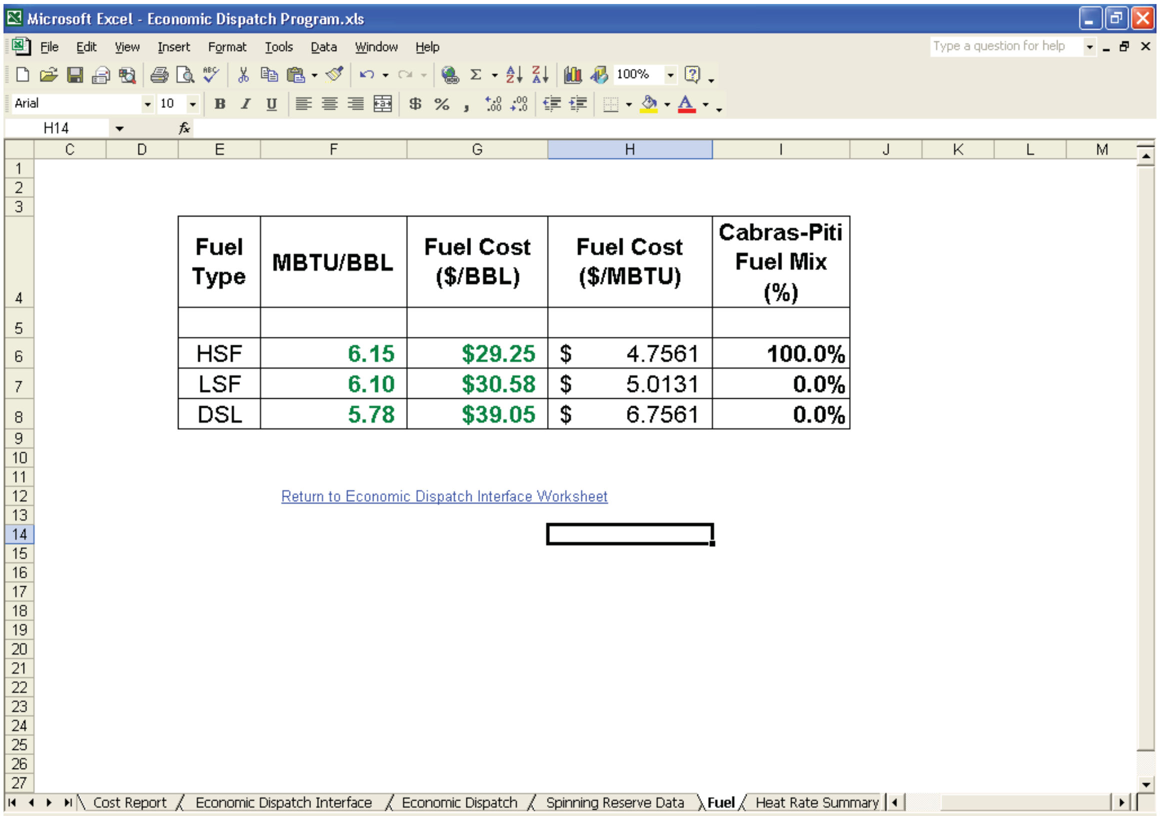
Spinning Reserve Requirement Used in Dispatch Calculations 41

CELLS WITH GREEN NUMBERS ARE USER DATA ENTRY FIELDS

<u>System Loss Contingency</u> – The minimum amount of excess energy to be available
<u>Largest Reserve Carried By a Single Unit</u> – The largest amount of MW in spinning reserve produced by one unit
<u>(Sum of Maximum Unit Commitment) - (Desired Generation)</u> – as stated
<u>On-line Reserve Capacity Spinning Reserve Contribution</u> – Actual amount of spinning reserve based on unused capacity of online units
<u>Required Spinning Reserve (Droop Method)</u> – Spinning reserve required if the system is allowed to drop to 58.5Hz
<u>Required Spinning Reserve</u> – Spinning reserve as a percentage of generation demand
<u>Spinning Reserve Computation Flag</u> – Flag marking how to calculate spinning reserve
1 – System Contingency Method 2 – Droop Method

5. Fuel Sheet

Contains fuel information used for calculations. Typically will be accessed when it is necessary to reflect changes in fuel prices.

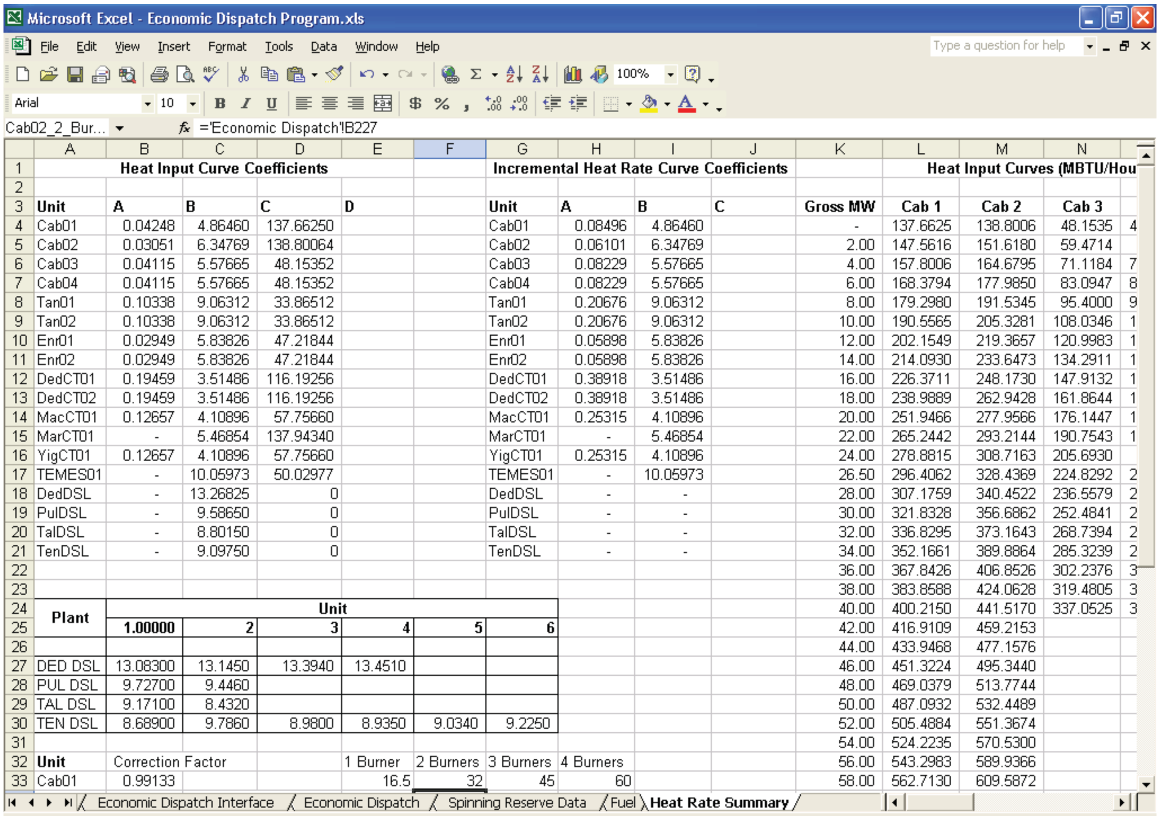


Fuel Type	MBTU/BBL	Fuel Cost ($/BBL)	Fuel Cost ($/MBTU)	Cabras-Piti Fuel Mix (%)
HSF	6.15	$29.25	$ 4.7561	100.0%
LSF	6.10	$30.58	$ 5.0131	0.0%
DSL	5.78	$39.05	$ 6.7561	0.0%

Fuel Type – High Sulfur, Low Sulfur and Diesel fuel types.
MBTU/BBL – Amount of energy produced by 1 barrel of fuel.
Fuel Cost ($/BBL) – The price of fuel per barrel.
Fuel Cost ($/MBTU) – The calculated cost to produce 1 MBTU.
Cabras-Piti Fuel Mix (%) – The mix of fuel used in the Cabras-Piti units.

6. Heat Rate Summary Sheet

This page deals with the technical specifications of the generation units. The data on this page are used to calculate the optimum distribution of load among the units. Data are based on results from periodical inspections of units.



Microsoft Excel - Economic Dispatch Program.xls

Cab02_2_Bur... ='Economic Dispatch'!B227

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	
1	**Heat Input Curve Coefficients**						**Incremental Heat Rate Curve Coefficients**					**Heat Input Curves (MBTU/Hou**			
2															
3	**Unit**	**A**	**B**	**C**	**D**		**Unit**	**A**	**B**	**C**	**Gross MW**	**Cab 1**	**Cab 2**	**Cab 3**	
4	Cab01	0.04248	4.86460	137.66250			Cab01	0.08496	4.86460		-	137.6625	138.8006	48.1535	4
5	Cab02	0.03051	6.34769	138.80064			Cab02	0.06101	6.34769		2.00	147.5616	151.6180	59.4714	
6	Cab03	0.04115	5.57665	48.15352			Cab03	0.08229	5.57665		4.00	157.8006	164.6795	71.1184	7
7	Cab04	0.04115	5.57665	48.15352			Cab04	0.08229	5.57665		6.00	168.3794	177.9850	83.0947	8
8	Tan01	0.10338	9.06312	33.86512			Tan01	0.20676	9.06312		8.00	179.2980	191.5345	95.4000	9
9	Tan02	0.10338	9.06312	33.86512			Tan02	0.20676	9.06312		10.00	190.5565	205.3281	108.0346	1
10	Enr01	0.02949	5.83826	47.21844			Enr01	0.05898	5.83826		12.00	202.1549	219.3657	120.9983	1
11	Enr02	0.02949	5.83826	47.21844			Enr02	0.05898	5.83826		14.00	214.0930	233.6473	134.2911	1
12	DedCT01	0.19459	3.51486	116.19256			DedCT01	0.38918	3.51486		16.00	226.3711	248.1730	147.9132	1
13	DedCT02	0.19459	3.51486	116.19256			DedCT02	0.38918	3.51486		18.00	238.9889	262.9428	161.8644	1
14	MacCT01	0.12657	4.10896	57.75660			MacCT01	0.25315	4.10896		20.00	251.9466	277.9566	176.1447	1
15	MarCT01	-	5.46854	137.94340			MarCT01	-	5.46854		22.00	265.2442	293.2144	190.7543	1
16	YigCT01	0.12657	4.10896	57.75660			YigCT01	0.25315	4.10896		24.00	278.8815	308.7163	205.6930	
17	TEMES01	-	10.05973	50.02977			TEMES01	-	10.05973		26.50	296.4062	328.4369	224.8292	2
18	DedDSL	-	13.26825	0			DedDSL	-	-		28.00	307.1759	340.4522	236.5579	2
19	PulDSL	-	9.58650	0			PulDSL	-	-		30.00	321.8328	356.6862	252.4841	2
20	TalDSL	-	8.80150	0			TalDSL	-	-		32.00	336.8295	373.1643	268.7394	2
21	TenDSL	-	9.09750	0			TenDSL	-	-		34.00	352.1661	389.8864	285.3239	2
22											36.00	367.8426	406.8526	302.2376	3
23											38.00	383.8588	424.0628	319.4805	3
24	**Plant**	**Unit**									40.00	400.2150	441.5170	337.0525	3
25		**1.00000**	**2**	**3**	**4**	**5**	**6**				42.00	416.9109	459.2153		
26											44.00	433.9468	477.1576		
27	DED DSL	13.08300	13.1450	13.3940	13.4510						46.00	451.3224	495.3440		
28	PUL DSL	9.72700	9.4460								48.00	469.0379	513.7744		
29	TAL DSL	9.17100	8.4320								50.00	487.0932	532.4489		
30	TEN DSL	8.68900	9.7860	8.9800	8.9350	9.0340	9.2250				52.00	505.4884	551.3674		
31											54.00	524.2235	570.5300		
32	**Unit**	Correction Factor			1 Burner	2 Burners	3 Burners	4 Burners			56.00	543.2983	589.9366		
33	Cab01	0.99133			16.5	32	45	60			58.00	562.7130	609.5872		

Economic Dispatch Interface / Economic Dispatch / Spinning Reserve Data / Fuel / **Heat Rate Summary**

Heat Input Curve Coefficients
Incremental Heat Rate Curve Coefficients
Heat Input Curves (MBTU/Hour)
Average Gross Heat Rate Curve (MBTU/MWh)
Incremental Gross Heat Rate Curve (MBTU/MWh)

Protected/Hidden Worksheets

The following sheets are normally hidden. Most are protected from user input without a proper password.

1. Availability

This is a sheet noting when units are available and what their maximum generation is. The sum of all the units' rating is calculated and checked against estimated peaks and color coded to what level can be met. The sheet does not appear to affect calculations and is protected from input.

2. Documentation

This overviews basic instructions on how to use this program in conjunction with Load Flow and Dynamic simulations to produce an optimal result accounting for security constraints as well as power required.

3. Unit Commitment

This sheet appears to be similar to the EDI sheet, however the values input here do not affect calculations. Possibly an older version of the EDI.

4. Mirror

A copy of the two tables from the Economic Dispatch page.

5. Heat Input Curves (RFO)

This graph of the shows the heat curves of Cabras 1 through 4, Tango 1&2, and Enron 1&2. It charts the heat need by each unit to generate power.

6. Incremental Gross Heat Rate

This graph of the shows the incremental heat curves of Cabras 1 through 4, Tango 1&2, and Enron 1&2. It charts the additional heat need by each unit to generate an additional MWh of energy as a function of the current output in MW.

7. Unit Capacity Summary

This is a table detailing the nameplate rated maximum and minimum of each unit.

8. Unit Off-shift Labor Costs

Used to calculate the cost of running a generation unit during non-standard hours. The sheet is protected from user input.

9. Chart1

This graph of the shows the heat curves of Cabras 1 through 3, Tango 1, and Enron 2. Similar to Heat Input Curves (RFO) graph except contains fewer units and lines are smooth and do not show data points.

10. Chart2

This graph of the shows the incremental heat curves of Cabras 1 through 3, Tango 1, and Enron 2. Similar to Incremental Gross Heat Rate graph except contains fewer units and lines are smooth and do not show data points.

11. Sheet1

This sheet calculates the heat input necessary to generated a desired amount of power for the Mac/Yig and TEMES units. Also calculates the heat per megawatt for each value.

12. Unit O&M Cost Summary

This sheet is used as a reference for the variable O&M costs of each unit. These costs are applied when the VOM flag is enabled. This sheet is protected from user input.

13. Cost Summary

The sheet displays the heat input coefficients which it uses to calculate the required heat for running units at varying power levels. The sheet contains tables for both the total heat required for running a unit, the amount of heat needed per megawatt, and the incremental heat rate. This is protected from user input.

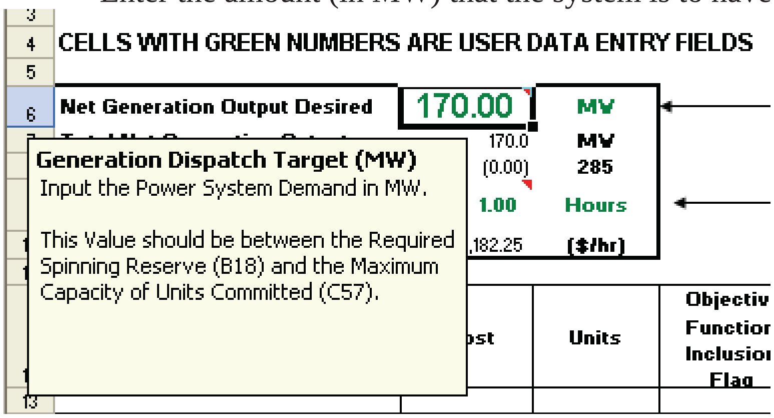
14. Crossover Points

Calculates at which power levels the gross heat rate curves cross and displays in two tables. The left one color codes results, black meaning there is no crossing point, while green indicates similar units or self comparison. The right one contains the same data but uses words rather than color coding. The sheet is protected from user input.

Usage of Program

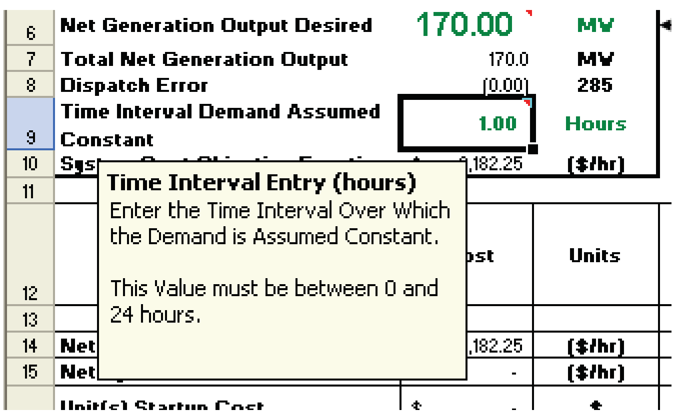
Step 1: Enter Generation Dispatch Target

Enter the amount (in MW) that the system is to have available for distribution.



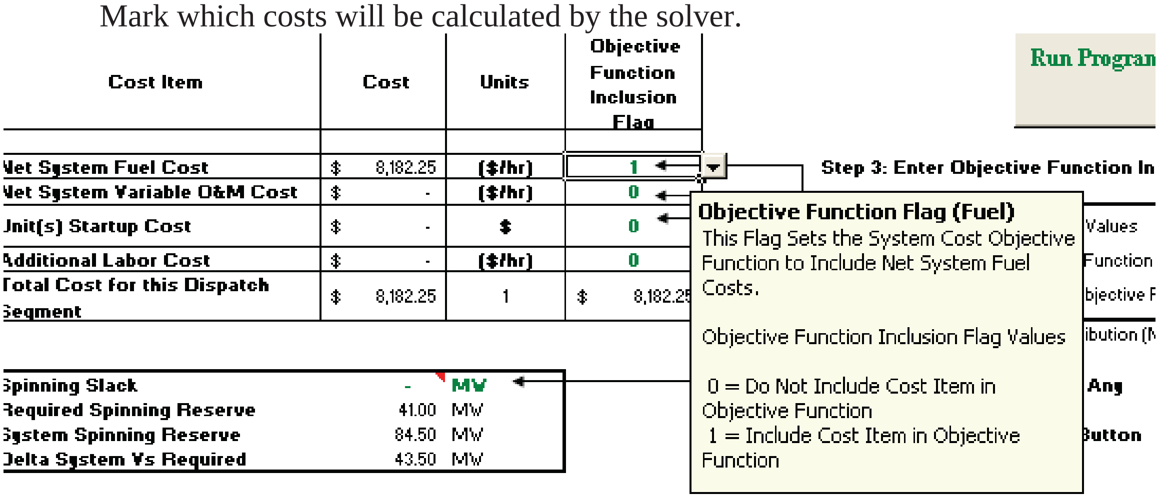
Step 2: Enter Time Interval Demand Assumed Constant

Enter the amount of time that the system will maintain this configuration.



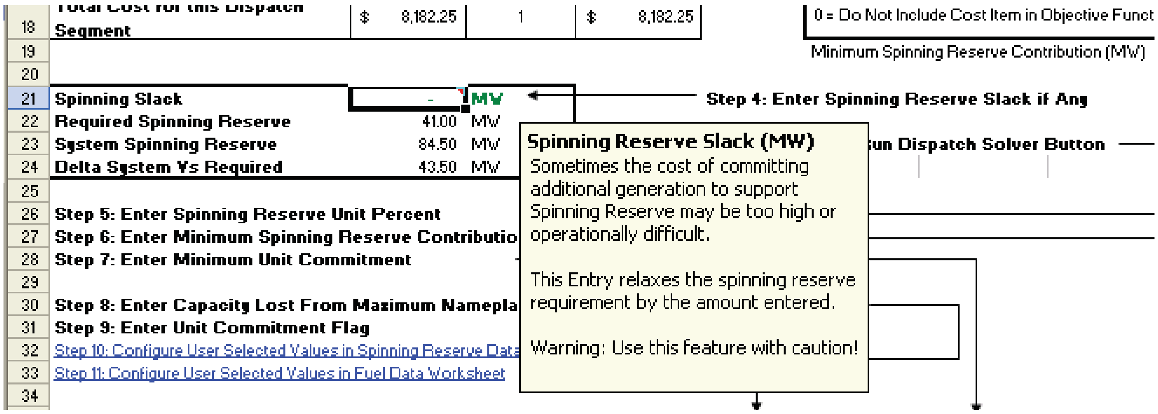
Step 3: Enter Objective Function Inclusion Flag

Mark which costs will be calculated by the solver.



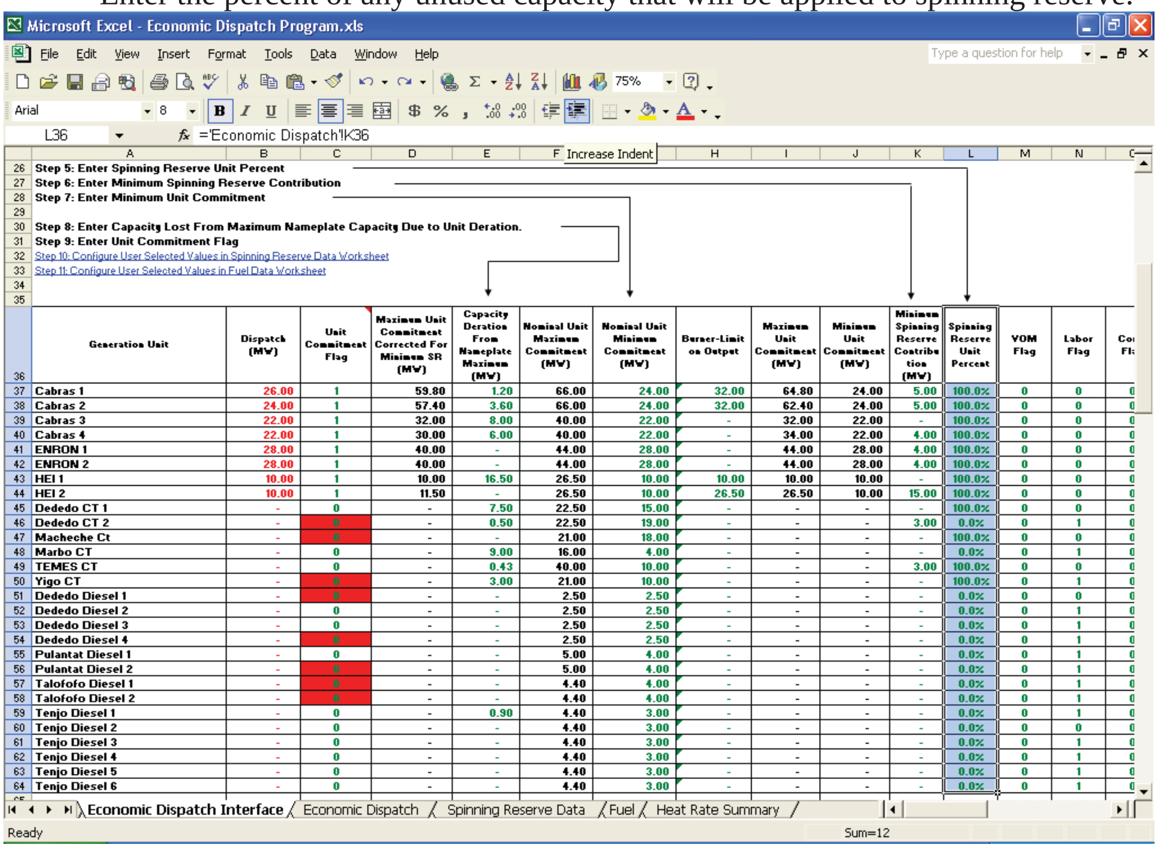
Step 4: Enter Spinning Reserve Slack if Any

Enter the amount, if any, by which the system can fall under the amount of spinning reserve that would otherwise be normally required. Warning, use this feature with caution.



Step 5: Enter Spinning Reserve Unit Percent

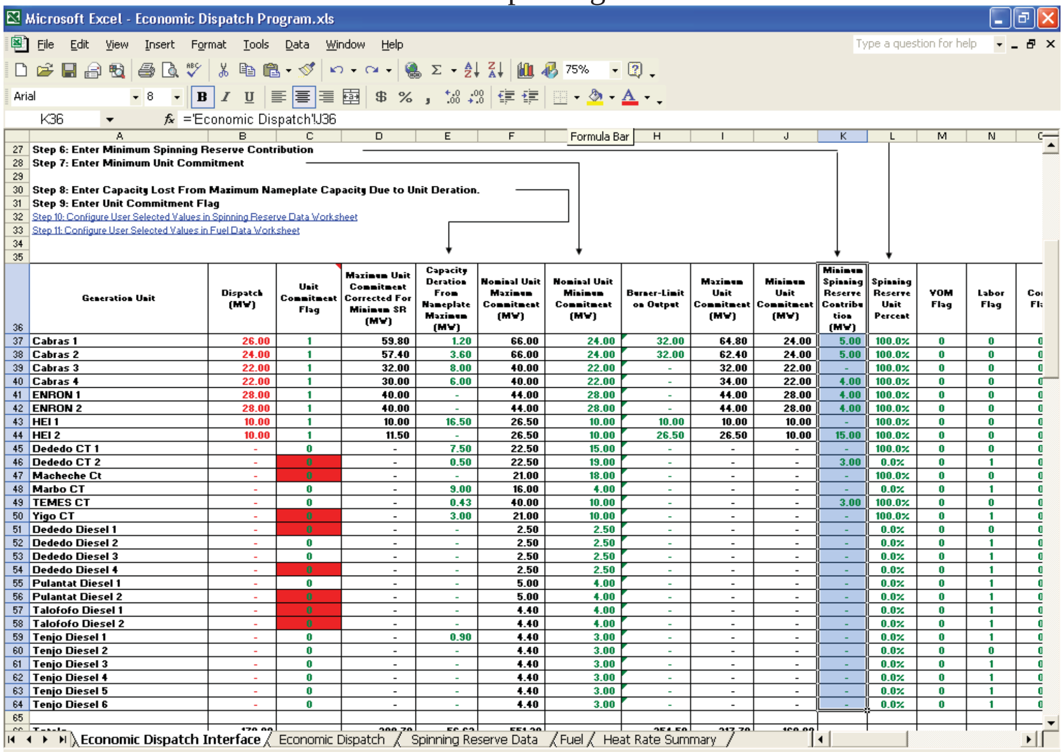
Enter the percent of any unused capacity that will be applied to spinning reserve.



Generation Unit	Dispatch (MW)	Unit Commitment Flag	Maximum Unit Commitment Corrected For Minimum SR (MW)	Capacity Deration From Nameplate Maximum (MW)	Nominal Unit Maximum Commitment (MW)	Nominal Unit Minimum Commitment (MW)	Burner-Limit on Output	Maximum Unit Commitment (MW)	Minimum Unit Commitment (MW)	Minimum Spinning Reserve Contribution (MW)	Spinning Reserve Unit Percent	VOM Flag	Labor Flag	Co Fl
Cabras 1	26.00	1	59.80	1.20	66.00	24.00	32.00	64.80	24.00	5.00	100.0%	0	0	0
Cabras 2	24.00	1	57.40	3.60	66.00	24.00	32.00	62.40	24.00	5.00	100.0%	0	0	0
Cabras 3	22.00	1	32.00	8.00	40.00	22.00	-	32.00	22.00	-	100.0%	0	0	0
Cabras 4	22.00	1	30.00	6.00	40.00	22.00	-	34.00	22.00	4.00	100.0%	0	0	0
ENRON 1	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
ENRON 2	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
HEI 1	10.00	1	10.00	16.50	26.50	10.00	10.00	10.00	10.00	-	100.0%	0	0	0
HEI 2	10.00	1	11.50	-	26.50	10.00	26.50	26.50	10.00	15.00	100.0%	0	0	0
Dededo CT 1	-	0	-	7.50	22.50	15.00	-	-	-	-	100.0%	0	0	0
Dededo CT 2	-	0	-	0.50	22.50	19.00	-	-	-	3.00	0.0%	0	1	0
Macheche Ct	-	0	-	-	21.00	18.00	-	-	-	-	100.0%	0	0	0
Marbo CT	-	0	-	9.00	16.00	4.00	-	-	-	-	0.0%	0	1	0
TEMES CT	-	0	-	0.43	40.00	10.00	-	-	-	3.00	100.0%	0	0	0
Yigo CT	-	0	-	3.00	21.00	10.00	-	-	-	-	100.0%	0	1	0
Dededo Diesel 1	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	0	0
Dededo Diesel 2	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 3	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 4	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 1	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 2	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 1	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 2	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 1	-	0	-	0.90	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 2	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	0	0
Tenjo Diesel 3	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 4	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 5	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 6	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0

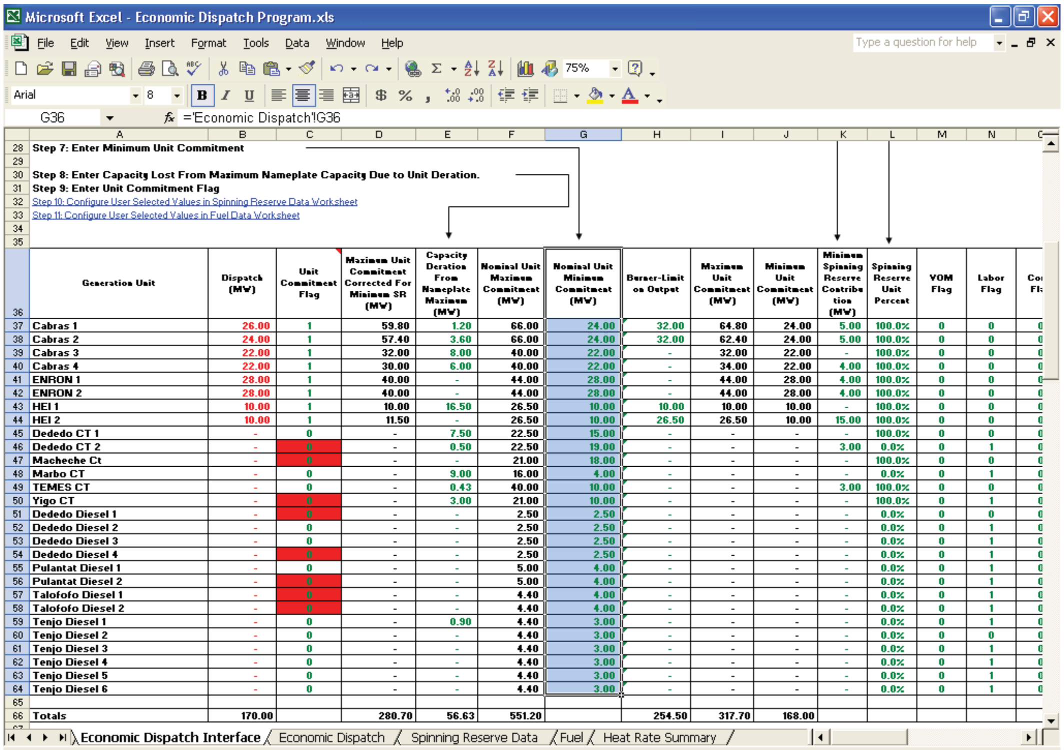
Step 6: Enter Minimum Spinning Reserve Contribution

Enter the minimum amount of spinning reserve that this unit is to have available.



Step 7: Enter Minimum Unit Commitment

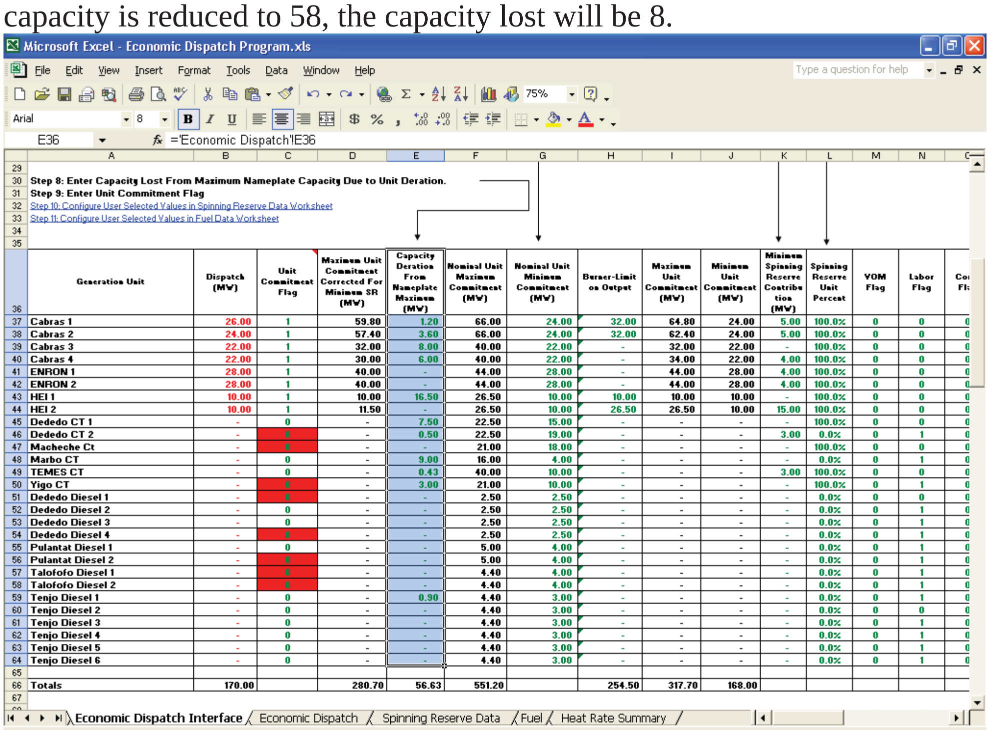
Enter the minimum output (in MW) sustainable for it. This will typically be from it's physical operating limitations, but may vary in certain circumstances.



Generation Unit	Dispatch (MW)	Unit Commitment Flag	Maximum Unit Commitment Corrected For Minimum SR (MW)	Capacity Deration From Nameplate Maximum (MW)	Nominal Unit Maximum Commitment (MW)	Nominal Unit Minimum Commitment (MW)	Burner-Limit on Output	Maximum Unit Commitment (MW)	Minimum Unit Commitment (MW)	Minimum Spinning Reserve Contribution (MW)	Spinning Reserve Unit Percent	VOM Flag	Labor Flag	Co Fl
Cabras 1	26.00	1	59.80	1.20	66.00	24.00	32.00	64.80	24.00	5.00	100.0%	0	0	0
Cabras 2	24.00	1	57.40	3.60	66.00	24.00	32.00	62.40	24.00	5.00	100.0%	0	0	0
Cabras 3	22.00	1	32.00	8.00	40.00	22.00	-	32.00	22.00	-	100.0%	0	0	0
Cabras 4	22.00	1	30.00	6.00	40.00	22.00	-	34.00	22.00	4.00	100.0%	0	0	0
ENRON 1	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
ENRON 2	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
HEI 1	10.00	1	10.00	16.50	26.50	10.00	10.00	10.00	10.00	-	100.0%	0	0	0
HEI 2	10.00	1	11.50	-	26.50	10.00	26.50	26.50	10.00	15.00	100.0%	0	0	0
Dededo CT 1	-	0	-	7.50	22.50	15.00	-	-	-	-	100.0%	0	0	0
Dededo CT 2	-	0	-	0.50	22.50	19.00	-	-	-	3.00	0.0%	0	1	0
Macheche Ct	-	0	-	-	21.00	18.00	-	-	-	-	100.0%	0	0	0
Marbo CT	-	0	-	9.00	16.00	4.00	-	-	-	-	0.0%	0	1	0
TEMES CT	-	0	-	0.43	40.00	10.00	-	-	-	3.00	100.0%	0	0	0
Yigo CT	-	0	-	3.00	21.00	10.00	-	-	-	-	100.0%	0	1	0
Dededo Diesel 1	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	0	0
Dededo Diesel 2	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 3	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 4	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 1	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 2	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 1	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 2	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 1	-	0	-	0.90	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 2	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	0	0
Tenjo Diesel 3	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 4	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 5	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 6	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Totals	170.00		280.70	56.63	551.20		254.50	317.70	168.00					

Step 8: Enter Capacity Lost From Maximum Nameplate Capacity Due to Unit Deration.

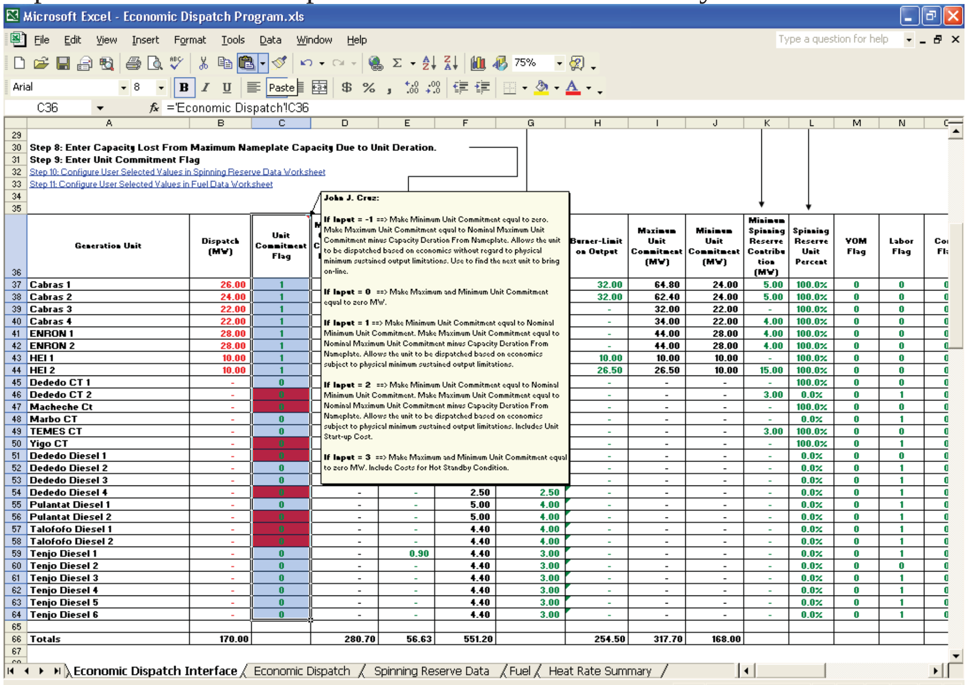
Enter the amount, if any, by which the units are operating below their nameplate capacity. For example, Cabras 1 has a NP rating of 66 but due to maintenance it’s capacity is reduced to 58, the capacity lost will be 8.



Generation Unit	Dispatch (MW)	Unit Commitment Flag	Maximum Unit Commitment Corrected For Minimum SR (MW)	Capacity Deration From Nameplate Maximum (MW)	Nominal Unit Maximum Commitment (MW)	Nominal Unit Minimum Commitment (MW)	Burner-Limit on Output	Maximum Unit Commitment (MW)	Minimum Unit Commitment (MW)	Minimum Spinning Reserve Contribution (MW)	Spinning Reserve Unit Percent	VOM Flag	Labor Flag	Co Fl
Cabras 1	26.00	1	59.80	1.20	66.00	24.00	32.00	64.80	24.00	5.00	100.0%	0	0	0
Cabras 2	24.00	1	57.40	3.60	66.00	24.00	32.00	62.40	24.00	5.00	100.0%	0	0	0
Cabras 3	22.00	1	32.00	8.00	40.00	22.00	-	32.00	22.00	-	100.0%	0	0	0
Cabras 4	22.00	1	30.00	6.00	40.00	22.00	-	34.00	22.00	4.00	100.0%	0	0	0
ENRON 1	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
ENRON 2	28.00	1	40.00	-	44.00	28.00	-	44.00	28.00	4.00	100.0%	0	0	0
HEI 1	10.00	1	10.00	16.50	26.50	10.00	10.00	10.00	10.00	-	100.0%	0	0	0
HEI 2	10.00	1	11.50	-	26.50	10.00	26.50	26.50	10.00	15.00	100.0%	0	0	0
Dededo CT 1	-	0	-	7.50	22.50	15.00	-	-	-	-	100.0%	0	0	0
Dededo CT 2	-	0	-	0.50	22.50	19.00	-	-	-	3.00	0.0%	0	1	0
Macheche Ct	-	0	-	-	21.00	18.00	-	-	-	-	100.0%	0	0	0
Marbo CT	-	0	-	9.00	16.00	4.00	-	-	-	-	0.0%	0	1	0
TEMES CT	-	0	-	0.43	40.00	10.00	-	-	-	3.00	100.0%	0	0	0
Yigo CT	-	0	-	3.00	21.00	10.00	-	-	-	-	100.0%	0	1	0
Dededo Diesel 1	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	0	0
Dededo Diesel 2	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 3	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Dededo Diesel 4	-	0	-	-	2.50	2.50	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 1	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Pulantat Diesel 2	-	0	-	-	5.00	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 1	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Talofofo Diesel 2	-	0	-	-	4.40	4.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 1	-	0	-	0.90	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 2	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	0	0
Tenjo Diesel 3	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 4	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 5	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Tenjo Diesel 6	-	0	-	-	4.40	3.00	-	-	-	-	0.0%	0	1	0
Totals	170.00		280.70	56.63	551.20		254.50	317.70	168.00					

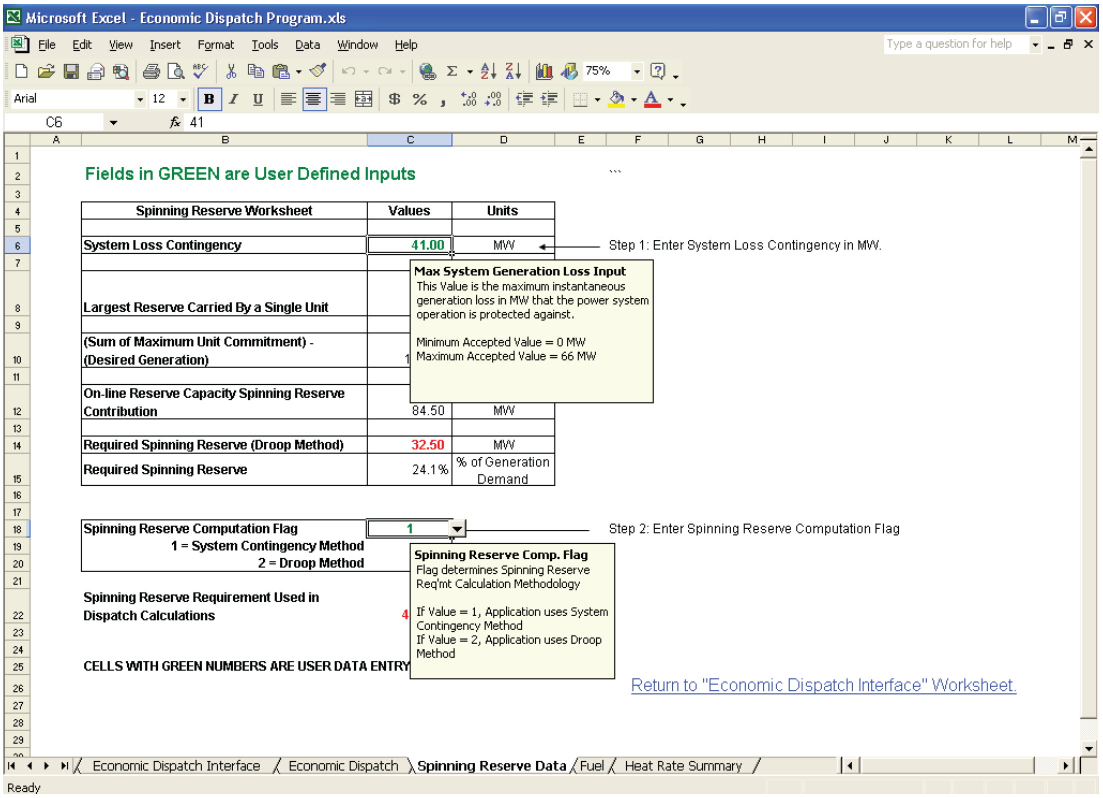
Step 9: Enter Unit Commitment Flag

Decide which units will be available in this scenario and under what conditions they will be available. See description of Unit Commitment Flag in the EDI Sheet explanation for a full report on the different availability modes.



Step 10: Configure User Selected Values in Spinning Reserve Data Worksheet

In the Spinning Reserve Data Worksheet enter the amount of spinning reserve to have available in the system loss contingency field. Then choose whether to use the system contingency method or the droop method.



Step 11: Configure User Selected Values in Fuel Data Worksheet

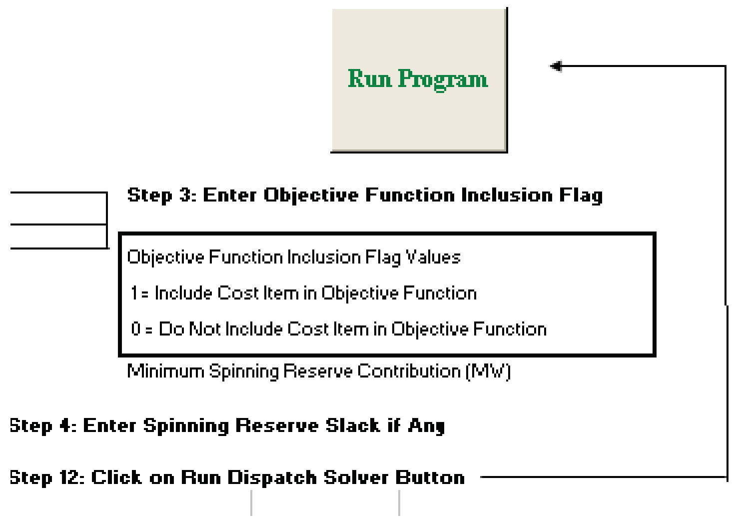
In the Fuel Data Worksheet update the thermal output of fuel types and fuel prices if necessary.

Fuel Type	MBTU/BBL	Fuel Cost ($/BBL)	Fuel Cost ($/MBTU)	Cabras-Piti Fuel Mix (%)
HSF	6.15	$29.25	$ 4.7561	100.0%
LSF	6.10	$30.58	$ 5.0131	0.0%
DSL	5.78	$39.05	$ 6.7561	0.0%

Return to Economic Dispatch Interface Worksheet

Step 12: Click on Run Dispatch Solver Button

Run the solver and it will either inform you that an acceptable solution was found, or that no solution within the given constraints could be found. If the solver succeeded then choose to keep the results. The results are indicated in the cost report worksheet. If the solver did not find a successful solution it may still be advisable to keep the values it used. These will be reflected in the values for cost analysis and on the EDI sheet. The Dispatch Error will indicate if the amount dispatched is under the required, likewise the Delta System vs Required for spinning reserve will indicate if there is sufficient reserve. If either number is negative, the system cannot support the current configuration and additional units must be brought online or the parameters adjusted.



Miscellaneous Information

Ctrl+S – Run Program
Ctrl+A – Run Solver to minimize System Cost

Cabras Fuel Mix must be adjusted by changing the percentages in the top right of the Economic Dispatch Worksheet.

Cabras units must be manually adjusted to change number of burners used. i.e. if the current setting for Dispatch is 27, the burner limit is 32, and is treated as the effective maximum for the unit, the unit must be set to 32 or higher to get to the next higher burner limit of 45. The effective range is now 32-45 for the unit, to use lower values in the solver the value must first be manually changed.
Limits: 0-16.5, 16.5-32, 32-45, 45-Maximum

Appendix V - Probabilistic Treatment of Guam Hourly Mean Wind Speed

SPORD maintains a dataset for Guam weather used in forecasts. This dataset includes Tiyan Weather Station data from January 1, 1964. However, the dataset has hourly information gaps until January 1, 1995. Since then there is complete 24 hour daily weather data. This analysis looks at the descriptive statistics for hourly mean wind speed. The impetus behind this investigation is to determine GPA's exposure to events where conservative measures for overhead transmission line thermal limits have merit. GPA should display an interest in this as the literature reports indicate that significant savings can be realized by accounting for dynamic thermal rating of overhead transmission lines. There is significant literature advocating dynamic rating that echo:

"The increases in [thermal] rating thereby achieved [sic] have led to significant savings in both capital and revenue costs of the 275 & 400 kV transmission system now owned and operated by the National Grid company plc." [1]

GPA's wind speed dataset contains hourly mean wind speed for each hour in the day starting at midnight. GPA divided this data into 22 classes from 0 mph to 20 in 1 mph increments and for wind speeds greater than 20 mph. Figure V-1 shows the results of this classification: class probabilities and cumulative distribution. Table V-2 summarizes this data and includes number of hours at each class.

Please note that 0 mph measured winds may map nonzero wind speeds to zero because these speeds are below the minimum anemometer turning speed. Additionally, the database was not screened for maintenance days when the anemometer(s) may not have been available. Thus, the statistics for 0 mph occurrences may be overstated.

Calculation of static thermal limits typically assumes two feet per second (ft/s) wind speeds or 1.36 mph. Therefore, cases where hourly mean wind speeds fall below 2 mph (critical wind speed) are noteworthy. The analysis indicates that this occurs about 5.75% of the time. On an annual basis this is 503.7 hours.

GPA next analyzed whether there is seasonality for the occurrences of critical wind speed. Tables V-3 through V-5 show the results for 0 mph, 1 mph, and 2 mph wind classes. Table V-6 summarizes this information. The analysis indicates that critical wind speeds are significantly more likely to occur in July through October. The probabilities of occurrence are appreciably lower between February through April and January. June is representative of the mean for the dataset period with a probability of 5.3% versus the period result, 5.75%.

GPA next investigated the days within the study period having at least one critical speed event. GPA investigated occurrences for strings of critical wind speed events on these days. Table V-7 shows the results. The percentage of days with at least one critical wind speed event is 34.11%. The percent of days with exactly one critical wind occurrence is 11.0%. WS00 is an event where there is an occurrence of 0 mph wind reported. WS01 is

[1] Lee, S.T.; Hoffman, S. "Power delivery reliability initiative bears fruit," *Computer Applications in Power, IEEE* , vol.14, no.3, pp.56-63, Jul 2001. doi: 10.1109/MCAP.2001.952938

an event where there is an occurrence of 1 mph wind reported. WS02 is an event where there is an occurrence of 2 mph wind reported. The number of days within the dataset with at Critical Wind Speed event is 1857 days. The Critical Wind Speed probabilities subtract days do not double count common days. For example, for exactly one Critical Wind Speed occurrence in a given day, adding up the number of days for WS00, WS01, and WS02 wind speeds would result in an over count of 23 days because there are days where more than one wind speed event occurs. The percent of days (probability) for having a Critical Wind Speed Event is 32.77%. A third of this is for one event in a single day. Table V-8 and Figure V-2 illustrate the seasonality of Critical Wind Speed Days. Almost 72% of Critical Wind Speed Days occur in the five months from June through October. July through October is typically the string of months with the highest rainfall. Collectively, about 40 inches of rain fall within those months.

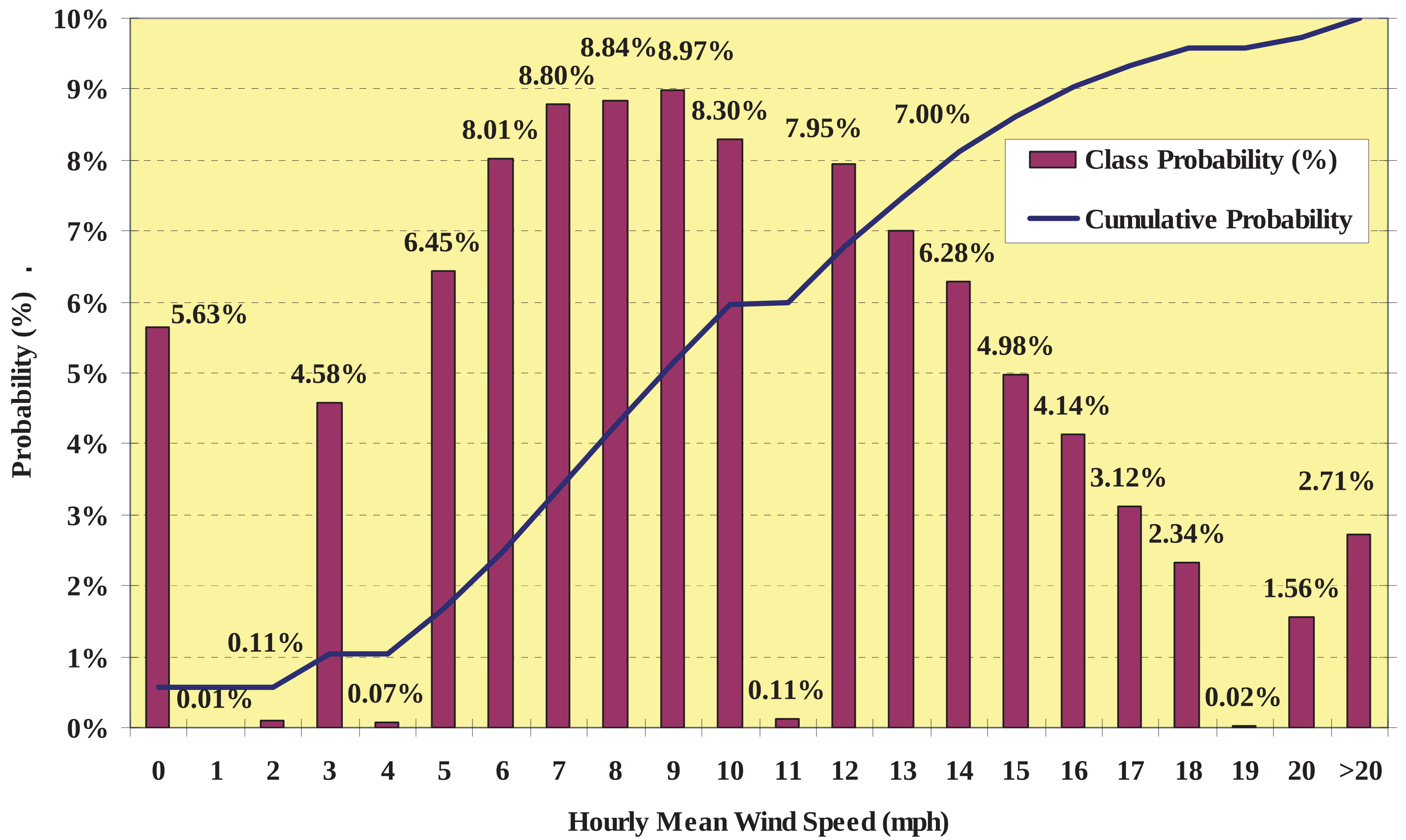


Figure V-1, Historical Hourly Mean Wind Speed (mph) – January 1, 1995 through April 30, 2010

Table V-2, Hourly Mean Wind Speed at Tiyan: January-1995 through April-2010

Hourly Mean Wind Speed (mph)	Class Probability (%)	Cumulative Probability (%)	Frequency (hours)
0	5.63%	5.63%	7,572
1	0.01%	5.64%	12
2	0.11%	5.75%	143
3	4.58%	10.33%	6,159
4	0.07%	10.41%	100
5	6.45%	16.85%	8,662
6	8.01%	24.86%	10,763
7	8.80%	33.66%	11,823
8	8.84%	42.50%	11,876
9	8.97%	51.47%	12,060
10	8.30%	59.78%	11,155
11	0.11%	59.89%	150
12	7.95%	67.84%	10,686
13	7.00%	74.84%	9,409
14	6.28%	81.12%	8,440
15	4.98%	86.10%	6,687
16	4.14%	90.24%	5,568
17	3.12%	93.37%	4,198
18	2.34%	95.70%	3,141
19	0.02%	95.73%	30
20	1.56%	97.29%	2,098
>20	2.71%	100.00%	3,644
Total	**100.00%**		**134,376**

Table V-3, Results: Hourly Mean Wind Speed at 0 mph Class

Month	Hours at HMWS = 0 mph	Total Hours (month)	Probability (%)
1	362	11,904	3.0%
2	123	10,848	1.1%
3	181	11,904	1.5%
4	128	11,520	1.1%
5	332	11,160	3.0%
6	573	10,800	5.3%
7	1325	11,160	11.9%
8	1388	11,160	12.4%
9	1680	10,800	15.6%
10	1039	11,160	9.3%
11	269	10,800	2.5%
12	172	11,160	1.5%
Period	**7572**	**134,376**	**5.6%**

Table V-4, Results: Hourly Mean Wind Speed at 1 mph Class

Month	Hours at HMWS = 1 mph	Total Hours (month)	Probability (%)
1	0	11,904	0.0000%
2	0	10,848	0.0000%
3	2	11,904	0.0168%
4	0	11,520	0.0000%
5	0	11,160	0.0000%
6	1	10,800	0.0093%
7	1	11,160	0.0090%
8	3	11,160	0.0269%
9	5	10,800	0.0463%
10	0	11,160	0.0000%
11	0	10,800	0.0000%
12	0	11,160	0.0000%
Period	**12**	**134,376**	**0.0089%**

Table V-5, Results: Hourly Mean Wind Speed at 2 mph Class

Month	Hours at HMWS = 2 mph	Total Hours (month)	Probability (%)
1	22	11,904	0.185%
2	31	10,848	0.286%
3	7	11,904	0.059%
4	1	11,520	0.009%
5	3	11,160	0.027%
6	5	10,800	0.046%
7	17	11,160	0.152%
8	21	11,160	0.188%
9	20	10,800	0.185%
10	14	11,160	0.125%
11	1	10,800	0.009%
12	1	11,160	0.009%
Period	**143**	**134,376**	**0.106%**

Table V-6, Summary: Hourly Mean Wind Speed (Critical Wind Speed Class)

Month	Hours at HMWS (Critical Wind Speeds)	Total Hours (month)	Probability (%)
1	384	11,904	3.23%
2	154	10,848	1.42%
3	190	11,904	1.60%
4	129	11,520	1.12%
5	335	11,160	3.00%
6	579	10,800	5.36%
7	1343	11,160	12.03%
8	1412	11,160	12.65%
9	1705	10,800	15.79%
10	1053	11,160	9.44%
11	270	10,800	2.50%
12	173	11,160	1.55%
Period	**7727**	**134,376**	**5.75%**

Table V-7, Results: Days within the Study Period Having Critical Speed Events

Label	Occurences in a Day	WS00 (days)	WS01 (days)	WS02 (days)	Critical Wind Speed (days)	Probability (%)
CST00	1	536	12	68	593	10.59%
CST01	2	293	0	10	302	5.39%
CST02	3	196	0	4	200	3.57%
CST03	4	165	0	2	167	2.98%
CST04	5	116	0	4	120	2.14%
CST05	6	103	0	1	104	1.86%
CST06	7	94	0	0	94	1.68%
CST07	8	64	0	0	64	1.14%
CST08	9	54	0	1	55	0.98%
CST09	10	46	0	0	46	0.82%
CST10	11	44	0	0	44	0.79%
CST11	12	30	0	0	30	0.54%
CST12	13	28	0	0	28	0.50%
CST13	14	15	0	0	15	0.27%
CST14	15	8	0	0	8	0.14%
CST15	16	6	0	0	6	0.11%
CST16	17	6	0	0	6	0.11%
CST17	18	2	0	0	2	0.04%
CST18	19	0	0	0	0	0.00%
CST19	20	0	0	0	0	0.00%
CST20	21	0	0	0	0	0.00%
CST21	22	1	0	0	1	0.02%
CST22	23	0	0	0	0	0.00%
CST23	24	1	0	0	1	0.02%
Temperature	**Average**	81.04	80.57	81.11		
	Max	84.79	83.96	84.50		
	Min	75.71	76.25	77.50		32.77%
	Mode	81.54	80.75	82.50		
	STD	1.50	1.61	1.64		

Table V-8, Results: Seasonality of Critical Speed Days

Month	Percent of CWS Days
1	4.48%
2	3.11%
3	3.01%
4	3.33%
5	5.85%
6	8.52%
7	15.41%
8	15.79%
9	17.65%
10	14.43%
11	5.08%
12	3.33%
	100.00%

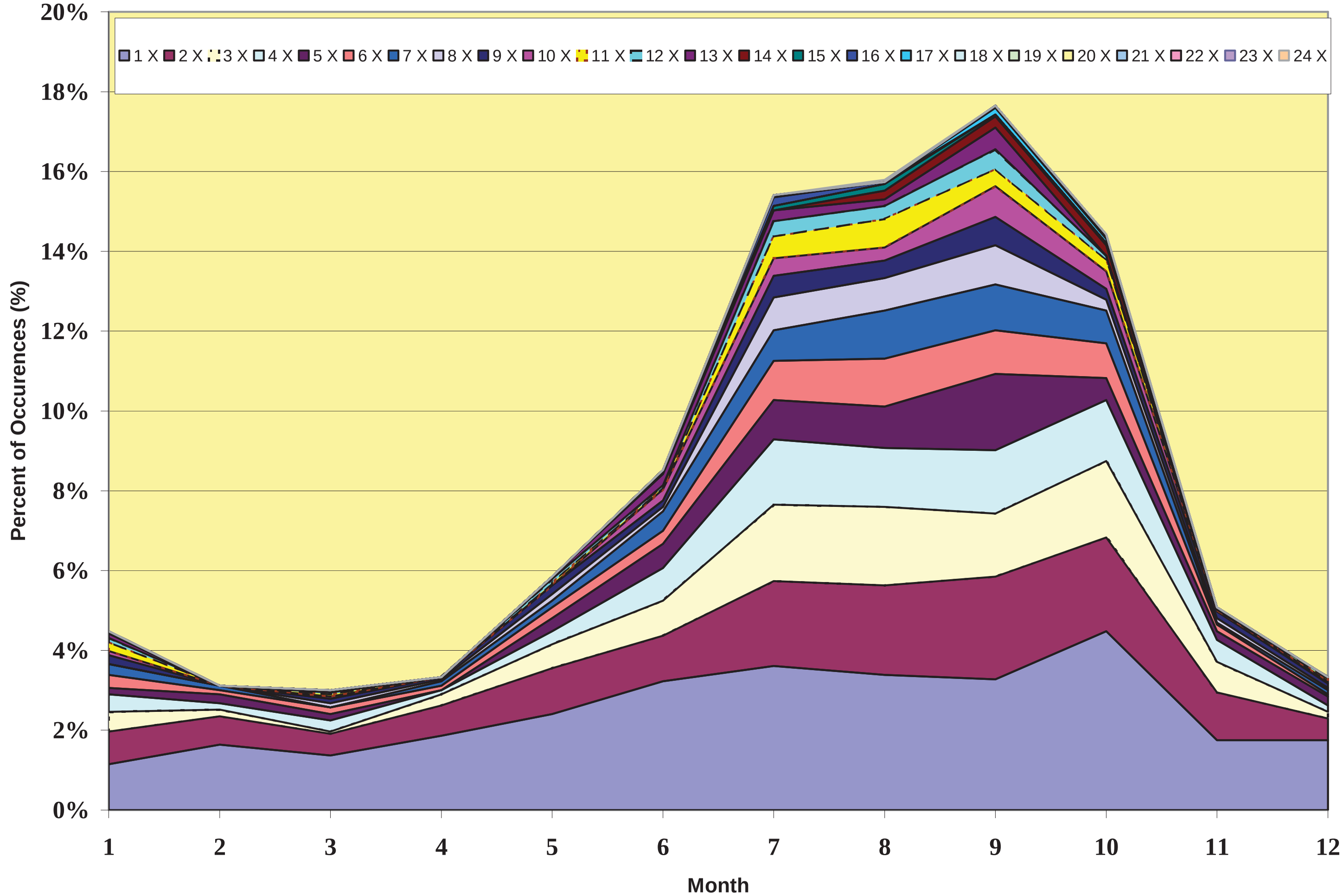


Figure V-2, Seasonal Distribution of Critical Wind Speeds Parameterized by Number of Hourly Occurrences within a Single Day

Appendix W - PSCC Dispatcher Logs

ATT: JOHN CRUZ.

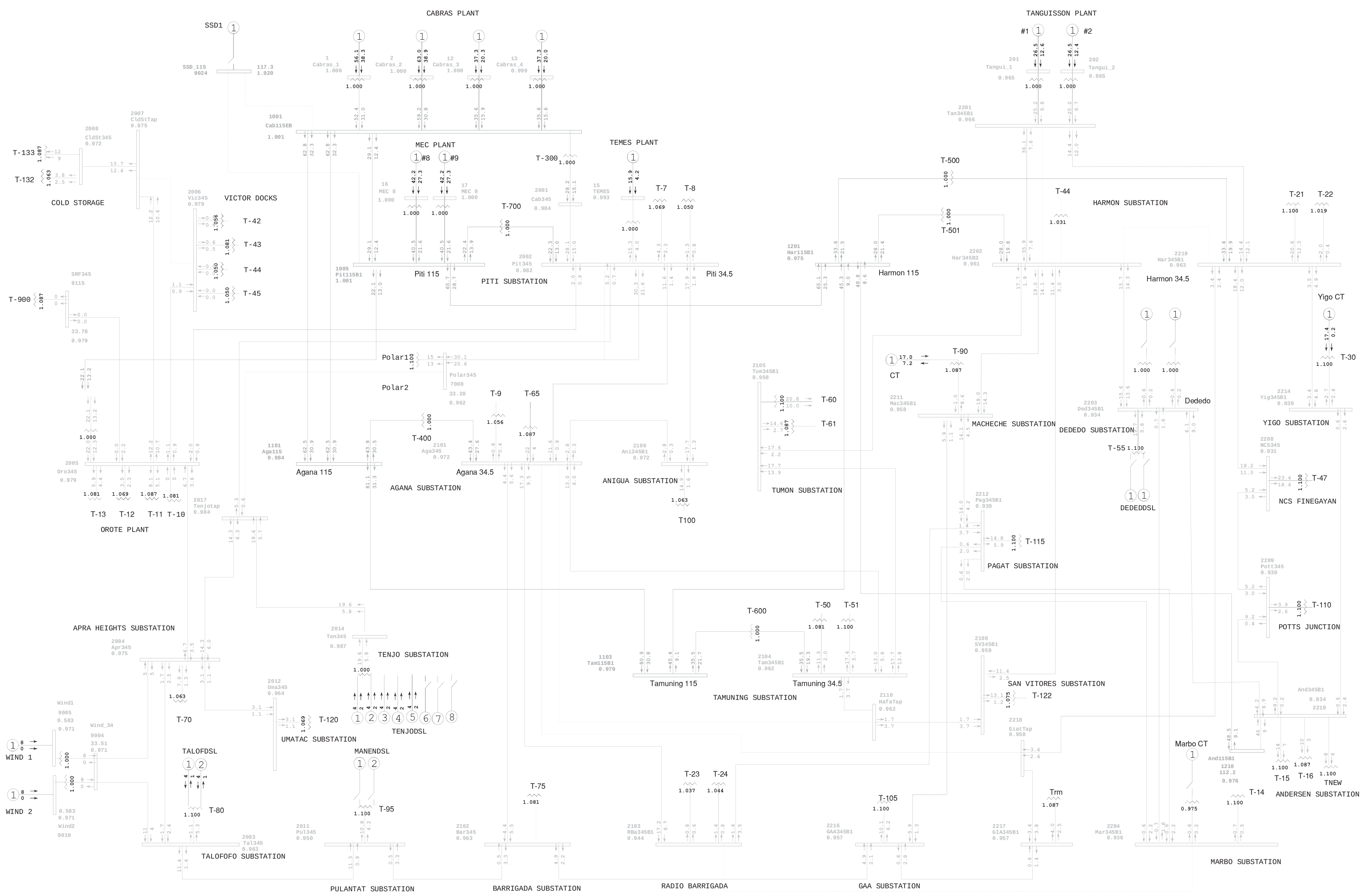
DATE: MAY 04 2010 TUESDAY.

TIME	TOTAL DSLS	TOTAL ON-LINE OPERABLE	TOTAL SYSTEM MVA	TOAL SYSTEM LOAD	Spining Reserve	Total System PF	CAB 1 KV	CAB 1 MW	CAB 1 AMPS	CAB 1 PF	CAB 2 KV	CAB 2 MW	CAB 2 AMPS	CAB 2 PF	CAB 3 KV	CAB 3 MW	CAB 3 AMPS	CAB 3 PF	CAB 4 KV	CAB 4 MW	CAB 4 AMPS	CAB 4 PF
0:00		347.0	88.4	214.0	133.0	.924	14.1	40.0	1789	.916	13.9	34.0	1480	.924	14.2	28.0	1286	.886	14.2	28.0	1265	.900
1:00		347.0	84.16	202.0	145.0	.923	14.1	38.0	1703	.914	13.9	34.0	1480	.954	14.2	26.0	1194	.885	14.2	26.0	1180	.896
2:00		347.0	81.52	197.0	150.0	.924	14.1	37.0	1652	.917	13.9	34.0	1419	.961	14.2	24.0	1107	.882	14.2	24.0	1101	.886
3:00		347.0	76.27	191.0	156.0	.932	14.1	37.0	1652	.917	13.9	34.0	1469	.961	14.1	22.0	1007	.895	14.1	22.0	993	.907
4:00		347.0	69.85	189.0	158.0	.938	14.1	38.0	1652	.942	13.9	31.0	1336	.964	14.1	22.0	1007	.895	14.1	22.0	993	.907
5:00		347.0	70.45	189.0	158.0	.937	14.1	38.0	1660	.937	13.9	31.0	1336	.964	14.1	22.0	1007	.895	14.1	22.0	993	.907
[illegible]		347.0	74.3	197.0	150.0	.936	14.1	37.0	1712	.933	13.9	34.0	1492	.947	14.1	22.0	1007	.895	14.1	22.0	993	.907
[illegible]		347.0	73.44	199.0	148.0	.938	14.1	37.0	1621	.935	13.9	34.0	1492	.947	14.1	24.0	1087	.904	14.1	24.0	1068	.920
8:00		347.0	79.55	207.0	140.0	.930	14.1	40.0	1723	.951	14.0	35.0	1605	.899	14.1	26.0	1173	.908	14.1	26.0	1169	.911
9:00		347.0	92.26	221.0	126.0	.922	14.1	40.0	1793	.914	14.0	35.0	1594	.906	14.2	33.0	1464	.917	14.2	33.0	1481	.906
10:00		347.0	93.21	227.0	120.0	.925	14.1	42.0	1840	.935	14.0	35.0	1605	.899	14.2	33.0	1464	.917	14.2	33.0	1481	.906
11:00		347.0	98.25	234.0	113.0	.920	14.1	41.0	1836	.914	14.0	35.0	1621	.890	14.2	33.0	1464	.917	14.2	33.0	1481	.906
12:00		347.0	98.12	230.0	117.0	.917	14.1	41.0	1832	.916	14.0	31.0	1496	.855	14.2	33.0	1464	.917	14.2	33.0	1481	.906
13:00		347.0	100.67	234.0	113.0	.916	14.1	41.0	1891	.888	13.9	35.0	1562	.931	14.2	33.0	1509	.889	14.2	33.0	1512	.887
14:00		347.0	106.48	237.0	110.0	.910	14.1	40.0	1828	.896	13.9	33.0	1520	.902	14.2	33.0	1509	.889	14.2	33.0	1512	.887
15:00		347.0	106.23	237.0	110.0	.911	14.0	40.0	1830	.900	13.9	35.0	1517	.889	14.2	33.0	1509	.889	14.2	33.0	1519	.887
16:00		347	106.32	236	111	.912	14.0	39	1813	.927	13.9	35	1602	.907	14.2	33	1509	.889	14.2	33	1512	.887
17:00		347	108.1	237	110	.910	14.0	40	1809	.907	13.9	35	1625	.895	14.2	33	1509	.889	14.2	33	1512	.887
[illegible]		347	107.35	236	111	.910	14.0	39	1812	.882	13.9	35	1621	.897	14.2	33	1509	.889	14.2	33	1512	.887
[illegible]		347	108.97	251	96	.917	14.0	39	1805	.911	13.9	38	1766	.894	14.2	33	1509	.889	14.2	33	1512	.887
20:00		347	110	251	96	.916	14.0	39	1809	.889	13.9	38	1783	.885	14.2	33	1509	.889	14.2	33	1512	.887
21:00		347	110.79	245	102	.915	14.0	37	1746	.914	13.9	38	1793	.880	14.2	33	1509	.884	14.2	33	1512	.882
22:00		347	105.76	231	116	.909	14.0	39	1789	.909	13.9	38	1711	.927	14.2	33	1509	.889	14.2	33	1511	.887
23:00		347	91.84	227	124	.917	14.0	39	1702	.913	14.9	22	1691	.933	14.2	29	1320	.887	14.2	29	1320	.889
24:00		347.0	94.85	212.0	136.0	.926	14.0	40.0	1762	.936	13.9	38.0	1668	.946	14.1	27.0	1242	.889	14.1	27.0	1216	.904

	PEAK LOAD	PF	TIME
AM	234.0	.920	1100
PM	251	.917	1900
1ST	GAN-MDS		0000 - 0800
2ND	FBG	FKR	0800 - 1600
3RD	PV	JC	

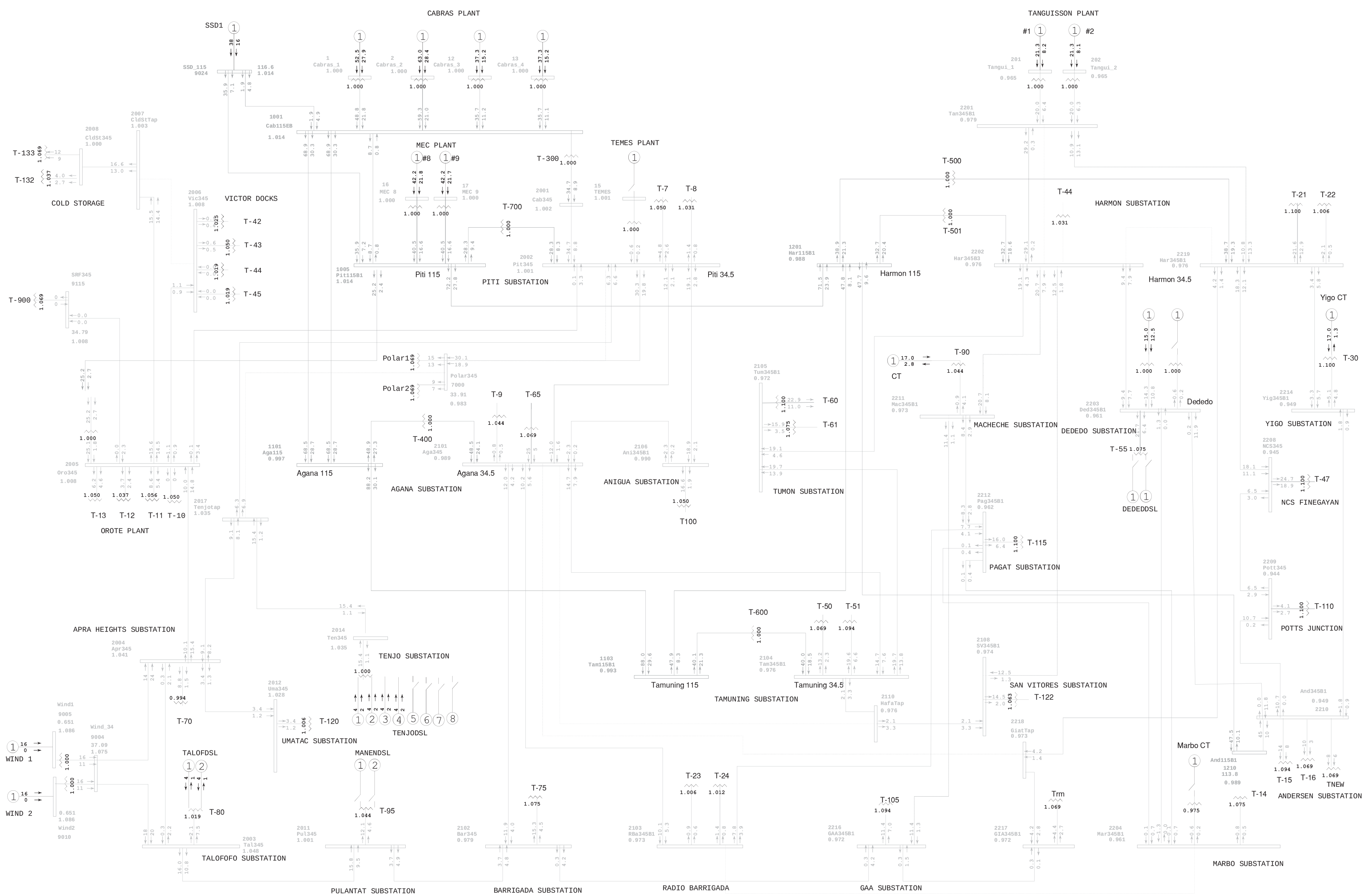
NOTES:

Appendix X - FY 2014, 2015, and 2020 Recommended Plan Single-Line Power Flow Diagrams



General Electric International, Inc. PSLF Program Mon May 24 15:18:55 2010 2015b-p1w40nfsa2.sav

Guam Power Authority Base Case Power Flow Peak Load Case 2015 with Upgrades		MW/MVAR gpa-oneline-2015b-p1w Rating = 4



General Electric International, Inc.   PSLF Program   Mon May 24 15:16:19 2010   2020b-p1w80pnfsa2.sav

Guam Power Authority Base Case Power Flow Peak Load Case 2020 with Upgrades		MW/MVAR gpa-oneline-2020b-p1w Rating = 4

Appendix Y - Leading Power Factor Email

From: Bruce Fredrick [fredribt@ussicorp.com]
Sent: Tuesday, May 11, 2010 11:04 AM
To: John J. Cruz, Jr.
Subject: Power factor

Hi John,

Quite some time back, you and I were discussing low power factor and the improvement that GPA currently is seeing through the use of distribution capacitors. During our conversation, I shared with you that during a training meeting in early 2009 at the USSI office in Harmon, our electrician installed a small power factor correction capacitor at our office on the 230 volt feed to our air conditioning unit to demonstrate how adding capacitance can improve power factor. To our surprise, the pf went from the 0.9 range down to the 0.8 range indicating that the power in this area was capacitive rather than inductive VAR loading. We have not rechecked the pf since that time.

Hope this helps.

Best Regards,
Bruce

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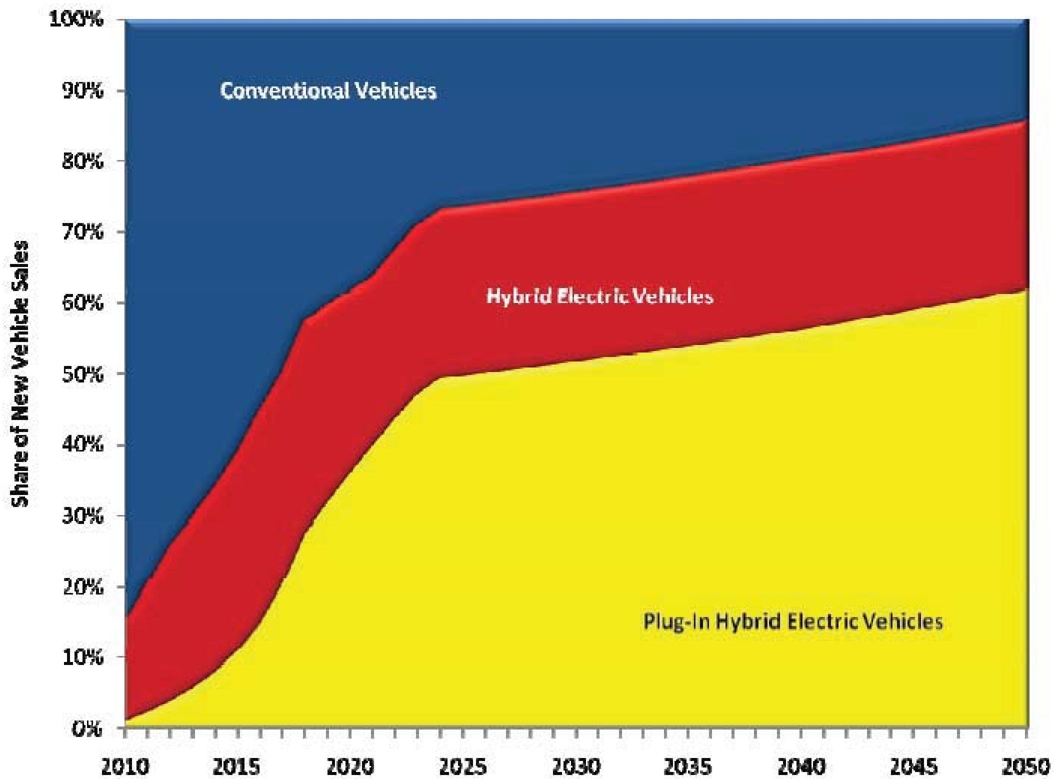
Appendix Z – Electric Vehicle Penetration Curves

Table Z-1, EPRI PHEV Penetration Curve[1]

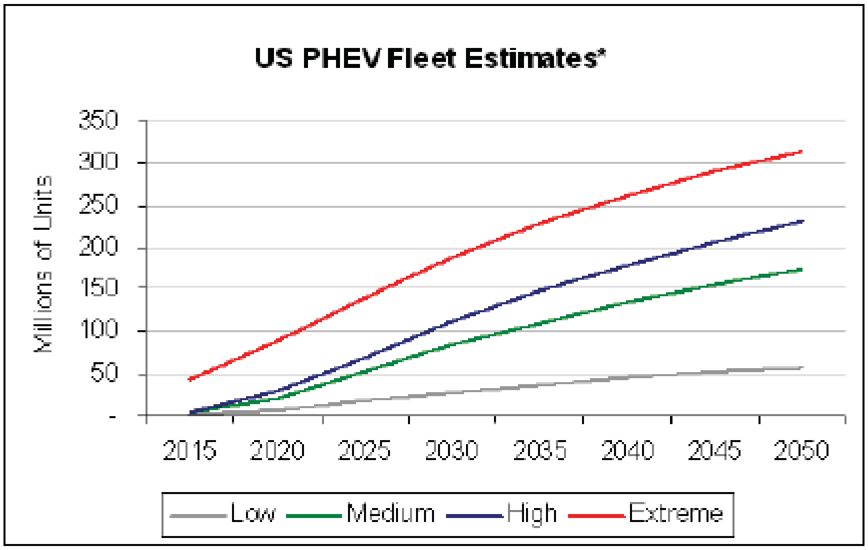
2050 New Vehicle Market Share by Scenario		Vehicle Type		
		Conventional	Hybrid	Plug-In Hybrid
PHEV Fleet Penetration Scenario	Low PHEV Fleet Penetration	56%	24%	20%
	Medium PHEV Fleet Penetration	14%	24%	62%
	High PHEV Fleet Penetration	5%	15%	80%



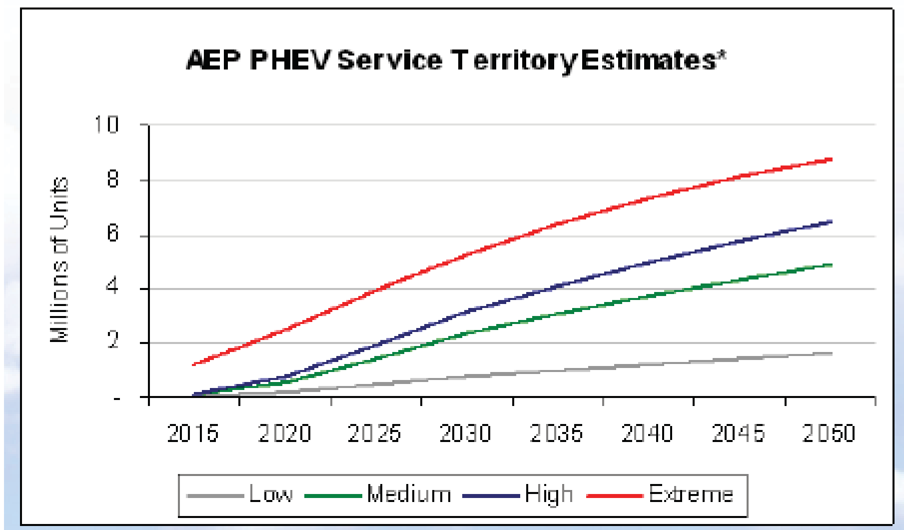
Assumed new car market share for the Medium PHEV scenario for conventional vehicles, hybrid electric vehicles, and plug-in hybrid electric vehicles for each vehicle category

[1] EPRI. *EPRI Executive Summary: Environmental Assessment of Plug-In Hybrid Electric Vehicles.* Palo Alto, CA: 2007. pg 6.

Table Z-2, AEP EV Penetration Curves[2]



*Low, Medium & High Scenarios based on EPRI's NRDC study. Assumes 5% annual retirement rate. AEP Fleet not included.



*We assume AEP's service territories will be slow to adopt due to low population densities (MSA) and low income per capita.

[2] Nora Fazio. *PHEV Financial Impacts*. American Electric Power: 2010. pg 4.

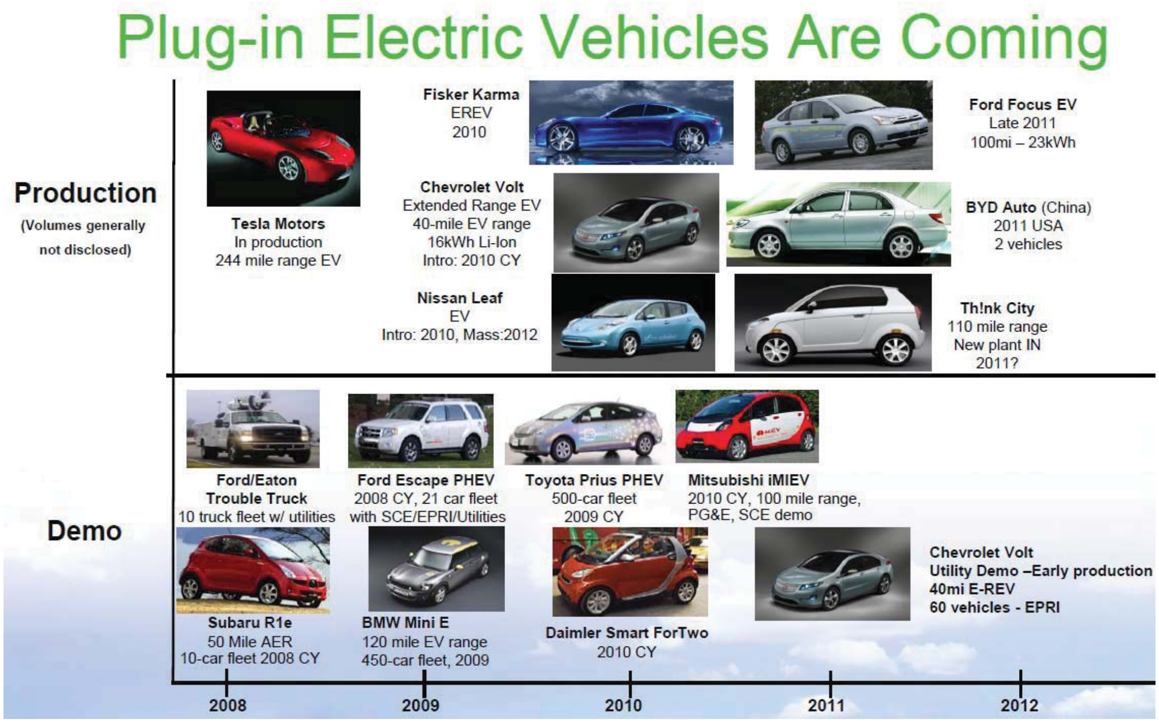


Figure Z-1, PEVs are Coming[3]

[3] Ibid. pg 3.

Type	Power Level	Charge Time	Reference	Impact
Level 1 120 VAC, 12-16A	1.4 kW	PHEV–5-8hrs BEV–14-30hrs	Hairdryer	
Level 2 240 VAC, 15-80A	3 – 19 kW (6.6 kW typical)	PHEV–1-3hrs BEV–2-8hrs	WH, Oven, Electric Furnace	
Level 3 500VDC, 20-200A	10 kW – 200kW +	PHEV–N/A BEV–15-30min	Small Comm. Bldg	

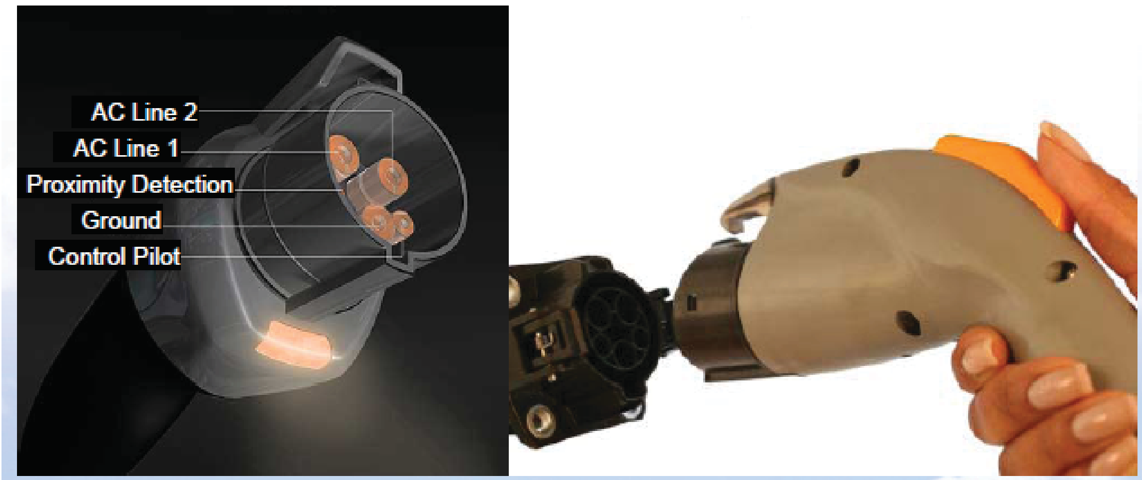


Figure Z-2, PEV Charging Regimens[4]

[4] Ibid. pg. 5.